UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2008

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ___ to ___.

Commission file number: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact name of Registrant as Specified in Its Charter)

Delaware	**76-0568219**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

1100 Louisiana, 10th Floor, Houston, Texas	**77002**
(Address of Principal Executive Offices)	(Zip Code)

(713) 381-6500
(Registrant's Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	**Name of Each Exchange On Which Registered**
Common Units	New York Stock Exchange

Securities to be registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☑	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☑

The aggregate market value of Enterprise Products Partners L.P.'s (or "EPD's") common units held by non-affiliates at June 30, 2008 was approximately $8.44 billion based on the closing price of such equity securities in the daily composite list for transactions on the New York Stock Exchange on June 30, 2008. This figure excludes common units beneficially owned by certain affiliates, including Dan L. Duncan. There were 449,944,731common units of EPD outstanding at March 2, 2009.

ENTERPRISE PRODUCTS PARTNERS L.P.
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SIGNIFICANT RELATIONSHIPS REFERENCED IN THIS ANNUAL REPORT

Unless the context requires otherwise, references to "we," "us," "our," or "Enterprise Products Partners" are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries.

References to "EPO" mean Enterprise Products Operating LLC as successor in interest by merger to Enterprise Products Operating L.P., which is a wholly owned subsidiary of Enterprise Products Partners through which Enterprise Products Partners conducts substantially all of its business.

References to "Duncan Energy Partners" mean Duncan Energy Partners L.P., which is a consolidated subsidiary of EPO. Duncan Energy Partners is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "DEP." References to "DEP GP" mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and is wholly owned by EPO.

References to "EPGP" mean Enterprise Products GP, LLC, which is our general partner.

References to "Enterprise GP Holdings" mean Enterprise GP Holdings L.P., a publicly traded affiliate, the units of which are listed on the NYSE under the ticker symbol "EPE." Enterprise GP Holdings owns EPGP. References to "EPE Holdings" mean EPE Holdings, LLC, which is the general partner of Enterprise GP Holdings.

References to "TEPPCO" mean TEPPCO Partners, L.P., a publicly traded affiliate, the common units of which are listed on the NYSE under the ticker symbol "TPP." References to "TEPPCO GP" refer to Texas Eastern Products Pipeline Company, LLC, which is the general partner of TEPPCO and is wholly owned by Enterprise GP Holdings.

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. ("ETP"). Energy Transfer Equity is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETE." The general partner of Energy Transfer Equity is LE GP, LLC ("LE GP"). On May 7, 2007, Enterprise GP Holdings acquired non-controlling interests in both LE GP and Energy Transfer Equity. Enterprise GP Holdings accounts for its investments in LE GP and Energy Transfer Equity using the equity method of accounting.

References to "Employee Partnerships" mean EPE Unit L.P. ("EPE Unit I"), EPE Unit II, L.P. ("EPE Unit II"), EPE Unit III, L.P. ("EPE Unit III"), Enterprise Unit L.P. ("Enterprise Unit") and EPCO Unit L.P. ("EPCO Unit"), collectively, all of which are private company affiliates of EPCO, Inc.

References to "EPCO" mean EPCO, Inc. and its wholly owned private company affiliates, which are related parties to all of the foregoing named entities.

We, EPO, Duncan Energy Partners, DEP GP, EPGP, Enterprise GP Holdings, EPE Holdings, TEPPCO and TEPPCO GP are affiliates under the common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This annual report contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "estimate," "forecast," "intend," "could," "should," "will," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions as described in more detail in Item 1A of this annual report. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements.

PART I

Items 1 and 2. *Business and Properties*.

General

We are a North American midstream energy company providing a wide range of services to producers and consumers of natural gas, natural gas liquids ("NGLs"), crude oil and certain petrochemicals. In addition, we are an industry leader in the development of pipeline and other midstream energy infrastructure in the continental United States and Gulf of Mexico. We conduct substantially all of our business through EPO. Our principal executive offices are located at 1100 Louisiana, 10th Floor, Houston, Texas 77002, our telephone number is (713) 381-6500 and our website is www.epplp.com.

We are a publicly traded Delaware limited partnership formed in 1998, the common units of which are listed on the NYSE under the ticker symbol "EPD." We are owned 98.0% by our limited partners and 2.0% by our general partner, EPGP. Our general partner is owned by a publicly traded affiliate, Enterprise GP Holdings, the common units of which are listed on the NYSE under the ticker symbol "EPE."

Business Strategy

We operate an integrated network of midstream energy assets that includes: natural gas gathering, treating, processing, transportation and storage; NGL fractionation (or separation), transportation, storage and import and export terminalling; crude oil transportation; offshore production platform services; and petrochemical transportation and services. Our business strategies are to:

- capitalize on expected increases in natural gas, NGL and crude oil production resulting from development activities in the Rocky Mountains, Midcontinent and U.S. Gulf Coast regions, including the Gulf of Mexico and Barnett Shale producing regions;
- capitalize on expected demand growth for natural gas, NGLs, crude oil and refined products;
- maintain a diversified portfolio of midstream energy assets and expand this asset base through growth capital projects and accretive acquisitions of complementary midstream energy assets;
- share capital costs and risks through joint ventures or alliances with strategic partners, including those that will provide the raw materials for these growth projects or purchase the project's end products; and
- increase fee-based cash flows by investing in pipelines and other fee-based businesses.

As noted above, part of our business strategy involves expansion through growth capital projects. We expect that these projects will enhance our existing asset base and provide us with additional growth opportunities in the future. For information regarding our growth capital projects, see "Liquidity and Capital Resources - Capital Spending" included under Item 7 of this annual report.

Financial Information by Business Segment

For information regarding our business segments, see Note 16 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. Such financial information is incorporated by reference into this Item 1 and 2 discussion.

Recent Developments

For information regarding our recent developments, see "Recent Developments" included under Item 7 of this annual report, which is incorporated by reference into this Item 1 and 2 discussion.

Segment Discussion

Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States, Canada and the Gulf of Mexico with domestic consumers and international markets. We have four reportable business segments:

- NGL Pipelines & Services;
- Onshore Natural Gas Pipelines & Services;
- Offshore Pipelines & Services; and
- Petrochemical Services.

Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

The following sections present an overview of our business segments, including information regarding the principal products produced, services rendered, seasonality, competition and regulation. Our results of operations and financial condition are subject to a variety of risks. For information regarding our key risk factors, see Item 1A of this annual report.

Our business activities are subject to various federal, state and local laws and regulations governing a wide variety of topics, including commercial, operational, environmental, safety and other matters. For a discussion of the principal effects such laws and regulations have on our business, see "Regulation" and "Environmental and Safety Matters" included within this Item 1 and 2.

Our revenues are derived from a wide customer base. During 2008 our largest customer was LyondellBasell Industries ("LBI") and its affiliates, which accounted for 9.6% of our consolidated revenues. In 2007 and 2006, our largest customer was The Dow Chemical Company and its affiliates, which accounted for 6.9% and 6.1%, respectively, of our consolidated revenues.

On January 6, 2009, LBI announced that its U.S. operations had voluntarily filed to reorganize under Chapter 11 of the U.S. Bankruptcy Code. At the time of the bankruptcy filing, we had approximately $17.3 million of credit exposure to LBI, which was reduced to approximately $10.0 million through remedies provided under certain pipeline tariffs. In addition, we are seeking to have LBI accept certain contracts and have filed claims pursuant to current Bankruptcy Court Orders that we expect will allow us to recover the majority of the remaining credit exposure.

For 2008, LBI accounted for 10.2%, or $1.6 billion, of revenues attributable to our NGL Pipelines & Services business segment and 19.2%, or $516.2 million, of revenues attributable to our Petrochemical Services business segment.

As generally used in the energy industry and in this document, the identified terms have the following meanings:

/d	= per day
BBtus	= billion British thermal units
Bcf	= billion cubic feet
MBPD	= thousand barrels per day
MMBbls	= million barrels
MMBtus	= million British thermal units
MMcf	= million cubic feet

The following discussion of our business segments provides information regarding our principal plants, pipelines and other assets. For information regarding our results of operations, including significant measures of historical throughput, production and processing rates, see Item 7 of this annual report.

NGL Pipelines & Services

Our NGL Pipelines & Services business segment includes our (i) natural gas processing business and related NGL marketing activities, (ii) NGL pipelines aggregating approximately 14,322 miles including our 7,808-mile Mid-America Pipeline System, (iii) NGL and related product storage facilities and (iv) NGL fractionation facilities located in Texas and Louisiana. This segment also includes our import and export terminal operations.

NGL products (ethane, propane, normal butane, isobutane and natural gasoline) are used as raw materials by the petrochemical industry, as feedstocks by refiners in the production of motor gasoline and by industrial and residential users as fuel. Ethane is primarily used in the petrochemical industry as a feedstock for ethylene production, one of the basic building blocks for a wide range of plastics and other chemical products. Propane is used both as a petrochemical feedstock in the production of ethylene and propylene and as a heating, engine and industrial fuel. Normal butane is used as a petrochemical feedstock in the production of ethylene and butadiene (a key ingredient of synthetic rubber), as a blendstock for motor gasoline and to derive isobutane through isomerization. Isobutane is fractionated from mixed butane (a mixed stream of normal butane and isobutane) or produced from normal butane through the process of isomerization, principally for use in refinery alkylation to enhance the octane content of motor gasoline, in the production of isooctane and other octane additives and in the production of propylene oxide. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is primarily used as a blendstock for motor gasoline or as a petrochemical feedstock.

Natural gas processing and related NGL marketing activities. At the core of our natural gas processing business are 24 processing plants located in Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. Natural gas produced at the wellhead especially in association with crude oil contains varying amounts of NGLs. This "rich" natural gas in its raw form is usually not acceptable for transportation in the nation's major natural gas pipeline systems or for commercial use as a fuel. Natural gas processing plants remove the NGLs from the natural gas stream, enabling the natural gas to meet pipeline and commercial quality specifications. In addition, on an energy equivalent basis, NGLs generally have a greater economic value as a raw material for petrochemical and motor gasoline production than their value as components of the natural gas stream. After extraction, we typically transport the mixed NGLs to a centralized facility for fractionation (or separation) into purity NGL products such as ethane, propane, normal butane, isobutane and natural gasoline. The purity NGL products can then be used in our NGL marketing activities to meet contractual requirements or sold on spot and forward markets.

When operating and extraction costs of natural gas processing plants are higher than the incremental value of the NGL products that would be extracted, the recovery levels of certain NGL products, principally ethane, may be reduced or eliminated. This leads to a reduction in NGL volumes available for transportation and fractionation.

In our natural gas processing activities, we enter into margin-band contracts, percent-of-liquids contracts, percent-of-proceeds contracts, fee-based contracts, hybrid contracts (a combination of percent-of-liquids and fee-based contract terms) and keepwhole contracts. Under margin-band and keepwhole contracts, we take ownership of mixed NGLs extracted from the producer's natural gas stream and recognize revenue when the extracted NGLs are delivered and sold to customers on NGL marketing sales contracts. In the same way, revenue is recognized under our percent-of-liquids contracts except that the volume of NGLs we earn and sell is less than the total amount of NGLs extracted from the producers' natural gas. Under a percent-of-liquids contract, the producer retains title to the remaining percentage of mixed NGLs we extract and generally bears the natural gas cost for shrinkage and plant fuel. Under a percent-of-proceeds contract, we share in the proceeds generated from the sale of the mixed NGLs we extract on the producer's behalf. If a cash fee for natural gas processing services is stipulated by the contract, we record revenue when the natural gas has been processed and delivered to the producer. The NGL volumes we earn and take title to in connection with our processing activities are referred to as our equity NGL production.

In general, our percent-of-liquids, hybrid and keepwhole contracts give us the right (but not the obligation) to process natural gas for a producer; thus, we are protected from processing at an economic loss during times when the sum of our costs exceeds the value of the mixed NGLs of which we would take ownership. Generally, our natural gas processing agreements have terms ranging from month-to-month to life of the producing lease. Intermediate terms of one to ten years are also common.

To the extent that we are obligated under our margin-band and keepwhole gas processing contracts to compensate the producer for the natural gas equivalent energy value of mixed NGLs we extract from the natural gas stream, we are exposed to various risks, primarily commodity price fluctuations. However, our margin band contracts contain terms which limit our exposure to such risks. The prices of natural gas and NGLs are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. Periodically, we attempt to mitigate these risks through the use of commodity financial instruments. For information regarding our use of commodity financial instruments, see "Commodity Risk Hedging Program" included under Item 7A of this annual report.

Our NGL marketing activities generate revenues from the sale and delivery of NGLs obtained through our processing activities and purchases from third parties on the open market. These sales contracts may also include forward product sales contracts. In general, the sales prices referenced in these contracts are market-related and can include pricing differentials for such factors as delivery location.

NGL pipelines, storage facilities and import/export terminals. Our NGL pipeline, storage and terminalling operations include approximately 14,322 miles of NGL pipelines, 157.2 MMBbls of working capacity of NGL and related product storage and two import/export facilities.

Our NGL pipelines transport mixed NGLs and other hydrocarbons from natural gas processing facilities, refineries and import terminals to fractionation plants and storage facilities; distribute and collect NGL products to and from fractionation plants, petrochemical plants and refineries; and deliver propane to customers along the Dixie Pipeline and certain sections of the Mid-America Pipeline System. Revenue from our NGL pipeline transportation agreements is generally based upon a fixed fee per gallon of liquids transported multiplied by the volume delivered. Accordingly, the results of operations for this business are generally dependent upon the volume of product transported and the level of fees charged to customers (including those charged to our NGL and petrochemical marketing activities, which are eliminated in consolidation). The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the Federal Energy Regulatory Commission ("FERC"). Typically, we do not take title to the products transported by our NGL pipelines; rather, the shipper retains title and the associated commodity price risk.

Our NGL and related product storage facilities are integral parts of our operations. In general, our underground storage wells are used to store our and our customers' mixed NGLs, NGL products and petrochemical products. Under our NGL and related product storage agreements, we charge customers monthly storage reservation fees to reserve storage capacity in our underground caverns. The customers pay reservation fees based on the quantity of capacity reserved rather than the actual quantity utilized. When a customer exceeds its reserved capacity, we charge those customers an excess storage fee. In addition, we charge our customers throughput fees based on volumes injected and withdrawn from the storage facility. Accordingly, the profitability of our storage operations is dependent upon the level of capacity reserved by our customers, the volume of product injected and withdrawn from our underground caverns and the level of fees charged.

We operate NGL import and export facilities located on the Houston Ship Channel in southeast Texas. Our import facility is primarily used to offload volumes for delivery to our NGL storage and fractionation facilities near Mont Belvieu, Texas. Our export facility includes an NGL products chiller and related equipment used for loading refrigerated marine tankers for third-party export customers. Revenues from our import and export services are primarily based on fees per unit of volume loaded or unloaded and may also include demand payments. Accordingly, the profitability of our import and export activities primarily depends on the available quantities of NGLs to be loaded and offloaded and the fees we charge for these services.

NGL fractionation. We own or have interests in eight NGL fractionation facilities located in Texas and Louisiana. NGL fractionation facilities separate mixed NGL streams into purity NGL products. The three primary sources of mixed NGLs fractionated in the United States are (i) domestic natural gas processing plants, (ii) domestic crude oil refineries and (iii) imports of butane and propane mixtures. The mixed NGLs delivered from domestic natural gas processing plants and crude oil refineries to our NGL fractionation facilities are typically transported by NGL pipelines and, to a lesser extent, by railcar and truck.

Mixed NGLs extracted by domestic natural gas processing plants represent the largest source of volumes processed by our NGL fractionators. Based upon industry data, we believe that sufficient volumes of mixed NGLs, especially those originating from Gulf Coast, Rocky Mountain and Midcontinent natural gas processing plants, will be available for fractionation in commercially viable quantities for the foreseeable future. Significant volumes of mixed NGLs are contractually committed to our NGL fractionation facilities by joint owners and third-party customers.

The majority of our NGL fractionation facilities process mixed NGL streams for third-party customers and support our NGL marketing activities under fee-based arrangements. These fees (typically in cents per gallon) are subject to adjustment for changes in certain fractionation expenses, including natural gas fuel costs. At our Norco facility, we perform fractionation services for certain customers under percent-of-liquids contracts. The results of operations of our NGL fractionation business are dependent upon the volume of mixed NGLs fractionated and either the level of fractionation fees charged (under fee-based contracts) or the value of NGLs received (under percent-of-liquids arrangements). Our fee-based customers generally retain title to the NGLs that we process for them; however, we are exposed to fluctuations in NGL prices (i.e., commodity price risk) to the extent we fractionate volumes for customers under percent-of-liquids arrangements. Periodically, we attempt to mitigate these risks through the use of commodity financial instruments. For information regarding our use of commodity financial instruments, see "Commodity Risk Hedging Program" included under Item 7A of this annual report.

Seasonality. Our natural gas processing and NGL fractionation operations exhibit little to no seasonal variation. Likewise, our NGL pipeline operations have not exhibited a significant degree of seasonality overall. However, propane transportation volumes are generally higher in the October through March timeframe in connection with increased use of propane for heating in the upper Midwest and southeastern United States. Our facilities located in the southern United States may be affected by weather events such as hurricanes and tropical storms originating in the Gulf of Mexico.

We operate our NGL and related product storage facilities based on the needs and requirements of our customers in the NGL, petrochemical, heating and other related industries. We usually experience an increase in the demand for storage services during the spring and summer months due to increased feedstock storage requirements for motor gasoline production and a decrease during the fall and winter months when propane inventories are being drawn for heating needs. In general, our import volumes peak during the spring and summer months and our export volumes are at their highest levels during the winter months.

In support of our commercial goals, our NGL marketing activities rely on inventories of mixed NGLs and purity NGL products. These inventories are the result of accumulated equity NGL production volumes, imports and other spot and contract purchases. Our inventories of ethane, propane and normal butane are typically higher on a seasonal basis from March through November as each are normally in higher demand and at higher price levels during winter months. Isobutane and natural gasoline inventories are generally stable throughout the year. Generally, our inventory cycle begins in late-February to mid-March (the seasonal low point), builds through September, and remains level until early December before being drawn through winter until the seasonal low is reached again.

Competition. Our natural gas processing business and NGL marketing activities encounter competition from fully integrated oil companies, intrastate pipeline companies, major interstate pipeline companies and their non-regulated affiliates, and independent processors. Each of our competitors has varying levels of financial and personnel resources, and competition generally revolves around price, service and location.

In the markets served by our NGL pipelines, we compete with a number of intrastate and interstate liquids pipelines companies (including those affiliated with major oil, petrochemical and gas companies) and barge, rail and truck fleet operations. In general, our NGL pipelines compete with these entities in terms of transportation fees and service.

Our competitors in the NGL and related product storage businesses are integrated major oil companies, chemical companies and other storage and pipeline companies. We compete with other storage service providers primarily in terms of the fees charged, number of pipeline connections and operational dependability. Our import and export operations also compete with those operated by major oil and chemical companies primarily in terms of loading and offloading volumes per hour.

We compete with a number of NGL fractionators in Texas, Louisiana and Kansas. Although competition for NGL fractionation services is primarily based on the fractionation fee charged, the ability of an NGL fractionator to receive mixed NGLs, store and distribute NGL products is also an important competitive factor and is a function of the existence of the necessary pipeline and storage infrastructure.

Properties. The following table summarizes the significant natural gas processing assets of our NGL Pipelines & Services business segment at February 2, 2009.

Description of Asset	Location(s)	Our Ownership Interest	Net Gas Processing Capacity (Bcf/d) (1)	Total Gas Processing Capacity (Bcf/d)
Natural gas processing facilities:				
Meeker (2)	Colorado	100.0%	1.40	1.40
Pioneer (3)	Wyoming	100.0%	1.30	1.30
Toca	Louisiana	67.4%	0.70	1.10
Chaco	New Mexico	100.0%	0.65	0.65
North Terrebonne	Louisiana	52.5%	0.63	1.30
Calumet	Louisiana	32.7%	0.51	1.60
Neptune	Louisiana	66.0%	0.43	0.65
Pascagoula	Mississippi	40.0%	0.40	1.50
Yscloskey	Louisiana	14.6%	0.34	1.85
Thompsonville	Texas	100.0%	0.30	0.30
Shoup	Texas	100.0%	0.29	0.29
Gilmore	Texas	100.0%	0.26	0.26
Armstrong	Texas	100.0%	0.25	0.25
Others (10 facilities) (4)	Texas, New Mexico, Louisiana	Various (5)	1.19	2.85
Total processing capacities			8.65	15.30

(1) The approximate net natural gas processing capacity does not necessarily correspond to our ownership interest in each facility. It is based on a variety of factors such as volumes processed at the facility and ownership interest in the facility.

(2) We commenced natural gas processing operations at our Meeker facility in October 2007 and subsequently began the Meeker Phase II expansion project to double the natural gas processing capacity to 1.4 Bcf/d at this facility. The Meeker Phase II expansion is expected to be operational during the first quarter of 2009.

(3) We acquired a silica gel natural gas processing facility from TEPPCO in March 2006 and subsequently increased the processing capacity from 0.3 Bcf/d to 0.6 Bcf/d. In addition, we constructed a new cryogenic processing facility having 0.7 Bcf/d of processing capacity, which became operational in February 2008.

(4) Includes our Venice, Sea Robin and Burns Point facilities located in Louisiana; Indian Basin and Carlsbad facilities located in New Mexico; and San Martin, Delmita, Sonora, Shilling and Indian Springs facilities located in Texas. Our ownership in the Venice plant is through our 13.1% equity method investment in Venice Energy Services Company, L.L.C. ("VESCO").

(5) Our ownership in these facilities ranges from 13.1% to 100.0%.

At the core of our natural gas processing business are 24 processing plants located in Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. Our natural gas processing facilities can be characterized as two distinct types: (i) straddle plants situated on mainline natural gas pipelines owned either by us or by third parties or (ii) field plants that process natural gas from gathering pipelines. We operate the Meeker, Pioneer, Toca, Chaco, North Terrebonne, Calumet, Neptune, Burns Point and Carlsbad plants and all of the Texas facilities. On a weighted-average basis, utilization rates for these assets were 66.4%, 66.4%, and 56.0% during the years ended December 31, 2008, 2007 and 2006, respectively. These rates reflect the periods in which we owned an interest in such facilities.

Our NGL marketing activities utilize a fleet of approximately 730 railcars, the majority of which are leased. These railcars are used to deliver feedstocks to our facilities and to distribute NGLs throughout the United States and parts of Canada. We have rail loading and unloading facilities in Alabama, Arizona, California, Kansas, Louisiana, Minnesota, Mississippi, Nevada, North Carolina and Texas. These facilities service both our rail shipments and those of our customers.

The following table summarizes the significant NGL pipelines and related storage assets of our NGL Pipelines & Services business segment at February 2, 2009.

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Useable Storage Capacity (MMBbls)
NGL pipelines:				
Mid-America Pipeline System	Midwest and Western U.S.	100.0%	7,808	
Dixie Pipeline	South and Southeastern U.S.	100.0% (1)	1,371	
Seminole Pipeline	Texas	90.0% (2)	1,342	
EPD South Texas NGL System	Texas	100.0% (3)	1,020	
Louisiana Pipeline System	Louisiana	Various (4)	612	
Skelly-Belvieu Pipeline	Texas	49.0% (5)	570	
Promix NGL Gathering System	Louisiana	50.0%	364	
DEP South Texas NGL Pipeline System	Texas	100.0% (3)	297	
Houston Ship Channel	Texas	100.0%	252	
Lou-Tex NGL	Texas, Louisiana	100.0%	205	
Others (6 systems) (6)	Various	Various	481	
Total miles			14,322	
NGL and related product storage facilities by state:				
Texas (7)				124.7
Louisiana				15.3
Kansas				7.5
Mississippi				5.7
Others (Arizona, Georgia, Iowa, Kansas, Nebraska, North Carolina, Oklahoma)				4.0
Total capacity (8)				157.2

(1) We acquired the remaining 25.8% ownership interest in this system during August 2008 and now own 100.0% of the Dixie Pipeline through our subsidiary, Dixie Pipeline Company (“Dixie”).
(2) We hold a 90.0% interest in this system through a majority owned subsidiary, Seminole Pipeline Company (“Seminole”).
(3) Reflects consolidated ownership of these systems by EPO (34.0%) and Duncan Energy Partners (66.0%).
(4) Of the 612 total miles for this system, we own 100.0% of 559 miles and 52.5% of the remaining 53 miles.
(5) Our ownership interest in this pipeline is held indirectly through our equity method investment in Skelly-Belvieu Pipeline Company, L.L.C. (“Skelly-Belvieu”), which we acquired in December 2008.
(6) Includes our Tri-States, Belle Rose, Wilprise, Chunchula and Bay Area pipelines located in the coastal regions of Alabama, Louisiana, Mississippi and Texas and our Meeker pipeline in Colorado. We acquired the remaining 16.7% ownership interest in Belle Rose NGL Pipeline, L.L.C. and an additional 16.7% interest in Tri-States NGL Pipeline, L.L.C. in October 2008.
(7) The amount shown for Texas includes 33 underground NGL and petrochemical storage caverns with an aggregate useable storage capacity of approximately 100 MMBbls that we own jointly with Duncan Energy Partners. These caverns are located in Mont Belvieu, Texas.
(8) The 157.2 MMBbls of total useable storage capacity includes 22.4 MMBbls held under long-term operating leases. The leased facilities are located in Texas, Louisiana and Kansas.

The maximum number of barrels that our NGL pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon the mix of products to be shipped and demand levels at various delivery points, the exact capacities of our NGL pipelines cannot be determined. We measure the utilization rates of such pipelines in terms of net throughput (i.e., on a net basis in accordance with our consolidated ownership interest). Total net throughput volumes for these pipelines were 1,747 MBPD, 1,583 MBPD and 1,450 MBPD during the years ended December 31, 2008, 2007 and 2006, respectively.

The following information highlights the general use of each of our principal NGL pipelines. We operate our NGL pipelines with the exception of Skelly-Belvieu Pipeline, Tri-States and a small portion of the Louisiana Pipeline System.

- The *Mid-America Pipeline System* is a regulated NGL pipeline system consisting of three primary segments: the 2,785-mile Rocky Mountain pipeline, the 2,771-mile Conway North pipeline and the 2,252-mile Conway South pipeline. This system covers thirteen states: Wyoming, Utah, Colorado, New Mexico, Texas, Oklahoma, Kansas, Missouri, Nebraska, Iowa, Illinois, Minnesota and Wisconsin. The Rocky Mountain pipeline transports mixed NGLs from the Rocky Mountain

Overthrust and San Juan Basin areas to the Hobbs hub located on the Texas-New Mexico border. During 2007, the Rocky Mountain pipeline's capacity was increased by 50 MBPD. The Conway North segment links the NGL hub at Conway, Kansas to refineries, petrochemical plants and propane markets in the upper Midwest. In addition, the Conway North segment has access to NGL supplies from Canada's Western Sedimentary Basin through third-party connections. The Conway South pipeline, which completed an expansion in 2007, connects the Conway hub with Kansas refineries and transports NGLs to and from Conway, Kansas to the Hobbs hub. The Mid-America Pipeline System interconnects with our Seminole Pipeline and Hobbs NGL fractionator and storage facility at the Hobbs hub. We also own fifteen unregulated propane terminals that are an integral part of the Mid-America Pipeline System.

During 2008, approximately 52.0% of the volumes transported on the Mid-America Pipeline System were mixed NGLs originating from natural gas processing plants located in the Permian Basin in west Texas, the Hugoton Basin of southwestern Kansas, the San Juan Basin of northwest New Mexico, the Piceance Basin of Colorado, the Uintah Basin of Colorado and Utah and the Greater Green River Basin of southwestern Wyoming. The remaining volumes are generally purity NGL products originating from NGL fractionators in the mid-continent areas of Kansas, Oklahoma, and Texas, as well as deliveries from Canada.

- The *Dixie Pipeline* is a regulated pipeline that extends from southeast Texas and Louisiana to markets in the southeastern United States and transports propane and other NGLs. Propane supplies transported on this system primarily originate from southeast Texas, southern Louisiana and Mississippi. This system operates in seven states: Texas, Louisiana, Mississippi, Alabama, Georgia, South Carolina and North Carolina.

- The *Seminole Pipeline* is a regulated pipeline that transports NGLs from the Hobbs hub and the Permian Basin area of west Texas to markets in southeastern Texas. NGLs originating on the Mid-America Pipeline System are the primary source of throughput for the Seminole Pipeline.

- The *EPD South Texas NGL System* is a network of NGL gathering and transportation pipelines located in south Texas. The system includes approximately 380 miles of pipeline used to gather and transport mixed NGLs from our south Texas natural gas processing facilities to our south Texas NGL fractionation facilities. The pipeline system also includes approximately 640 miles of pipelines that deliver NGLs from our south Texas fractionation facilities to refineries and petrochemical plants located between Corpus Christi and Houston, Texas and within the Texas City-Houston area, as well as to common carrier NGL pipelines.

  We contributed a 66.0% equity interest in Enterprise GC, LP ("Enterprise GC"), our subsidiary that owns the EPD South Texas NGL Pipeline, to Duncan Energy Partners effective December 8, 2008. We own, through our other subsidiaries, the remaining 34.0% equity interest in Enterprise GC. For additional information regarding this transaction, see "Other Items – Duncan Energy Partners Transactions" included under Item 7 of this annual report.

- The *Louisiana Pipeline System* is a network of NGL pipelines located in Louisiana. This system transports NGLs originating in southern Louisiana and in Texas to refineries and petrochemical companies along the Mississippi River corridor in southern Louisiana. This system also provides transportation services for our natural gas processing plants, NGL fractionators and other facilities located in Louisiana.

- The *Skelly-Belvieu Pipeline* is a regulated pipeline that transports mixed NGLs from Skellytown, Texas to markets in southeast Texas. Volumes originating on the Mid-America Pipeline System and NGLs produced at local refineries are the primary source of throughput for the Skelly-Belvieu Pipeline.

- The *Promix NGL Gathering System* is a NGL pipeline system that gathers mixed NGLs from natural gas processing plants in Louisiana for delivery to an NGL fractionator owned by K/D/S

Promix, L.L.C. ("Promix"). This gathering system is an integral part of the Promix NGL fractionation facility. Our ownership interest in this pipeline is held indirectly through our equity method investment in Promix.

- The *DEP South Texas NGL Pipeline System* transports NGLs from our Shoup and Armstrong fractionation facilities in south Texas to Mont Belvieu, Texas.

- The *Houston Ship Channel* pipeline system is a collection of pipelines interconnecting our Mont Belvieu facilities with our Houston Ship Channel import/export terminals and various third party petrochemical plants, refineries and other pipelines located along the Houston Ship Channel. This system is used to deliver NGL products to third-party petrochemical plants and refineries as well as to deliver feedstocks to our Mont Belvieu facilities.

- The *Lou-Tex NGL* pipeline system is used to provide transportation services for NGLs and refinery grade propylene between the Louisiana and Texas markets. We also use this pipeline to transport mixed NGLs from Mont Belvieu to our Louisiana Pipeline System.

Our NGL and related product storage facilities are integral parts of our pipeline and other operations. In general, these underground storage facilities are used to store NGLs and petrochemical products for us and our customers. We operate these facilities, with the exception of certain Louisiana storage locations operated for us by a third party.

Duncan Energy Partners, one of our consolidated subsidiaries, owns a 66.0% equity interest in our subsidiary, Mont Belvieu Caverns, LLC ("Mont Belvieu Caverns"). We own, through our other subsidiaries, the remaining 34.0% equity interest in Mont Belvieu Caverns. Mont Belvieu Caverns owns 33 underground NGL and petrochemical storage caverns with an aggregate storage capacity of approximately 100 MMBbls, a brine system with approximately 20 MMBbls of above-ground brine storage pit capacity and two brine production wells. These assets store and deliver NGLs (such as ethane and propane) and certain refined and petrochemical products for industrial customers located along the upper Texas Gulf Coast.

The following table summarizes the significant NGL fractionation assets of our NGL Pipelines & Services business segment at February 2, 2009.

Description of Asset	**Location(s)**	**Our Ownership Interest**	**Net Plant Capacity (MBPD)** (1)	**Total Plant Capacity (MBPD)**
NGL fractionation facilities:				
Mont Belvieu	Texas	75.0%	178	230
Shoup and Armstrong	Texas	100.0% (2)	87	87
Hobbs	Texas	100.0%	75	75
Norco	Louisiana	100.0%	75	75
Promix	Louisiana	50.0%	73	145
BRF	Louisiana	32.2%	19	60
Tebone	Louisiana	52.5%	12	30
Total plant capacities			519	702

(1) The approximate net NGL fractionation capacity does not necessarily correspond to our ownership interest in each facility. It is based on a variety of factors such as volumes processed at the facility and ownership interest in the facility.

(2) Reflects consolidated ownership of these fractionators by EPO (34.0%) and Duncan Energy Partners (66.0%).

The following information highlights the general use of each of our principal NGL fractionation facilities. We operate all of our NGL fractionation facilities.

- Our *Mont Belvieu* NGL fractionation facility is located at Mont Belvieu, Texas, which is a key hub of the domestic and international NGL industry. This facility fractionates mixed NGLs from several major NGL supply basins in North America including the Mid-Continent, Permian Basin, San Juan Basin, Rocky Mountains, East Texas and the Gulf Coast.

- Our *Shoup* and *Armstrong* NGL fractionation facilities fractionate mixed NGLs supplied by our south Texas natural gas processing plants. In turn, the Shoup and Armstrong facilities supply NGLs transported by the DEP South Texas NGL Pipeline System.

  We contributed a 66.0% equity interest in Enterprise GC, our subsidiary that owns the Shoup and Armstrong NGL fractionators, to Duncan Energy Partners effective December 8, 2008. We own through our other subsidiaries the remaining 34.0% equity interest in Enterprise GC. For additional information regarding this transaction, see "Other Items – Duncan Energy Partners Transactions" included under Item 7 of this annual report.

- Our *Hobbs* NGL fractionation facility is located in Gaines County, Texas, where it serves petrochemical end users and refineries in West Texas, New Mexico and California. In addition, the Hobbs facility can supply exports to northern Mexico through existing third-party pipeline infrastructure. The Hobbs facility receives mixed NGLs from several major supply basins including Mid-Continent, Permian Basin, San Juan Basin and the Rocky Mountains. The facility is strategically located at the interconnect of our Mid-America Pipeline System and Seminole Pipeline, providing us flexibility to supply the nation's largest NGL hub at Mont Belvieu, Texas as well as access to the second-largest NGL hub at Conway, Kansas.

- Our *Norco* NGL fractionation facility receives mixed NGLs via pipeline from refineries and natural gas processing plants located in southern Louisiana and along the Mississippi and Alabama Gulf Coast, including our Yscloskey, Pascagoula, Venice and Toca facilities.

- The *Promix* NGL fractionation facility receives mixed NGLs via pipeline from natural gas processing plants located in southern Louisiana and along the Mississippi Gulf Coast, including our Calumet, Neptune, Burns Point and Pascagoula facilities. In addition to the 364-mile Promix NGL Gathering System, Promix owns five NGL storage caverns and a barge loading facility that are integral to its operations.

- The *BRF* facility fractionates mixed NGLs from natural gas processing plants located in Alabama, Mississippi and southern Louisiana.

On a weighted-average basis, utilization rates for our NGL fractionators were 83.3%, 77.7% and 72.2% during the years ended December 31, 2008, 2007 and 2006, respectively. These rates reflect the periods in which we owned an interest in such facilities. We own direct consolidated interests in all of our NGL fractionation facilities with the exception of a 50.0% interest in the facility owned by Promix and a 32.2% interest in the facility owned by Baton Rouge Fractionators LLC ("BRF").

Our NGL operations include import and export facilities located on the Houston Ship Channel in southeast Texas. We own an import and export facility located on land we lease from Oiltanking Houston LP ("OTTI"). Our OTTI import facility can offload NGLs from tanker vessels at rates up to 20,000 barrels per hour depending on the product. Our OTTI export facility can load cargoes of refrigerated propane and butane onto tanker vessels at rates up to 6,700 barrels per hour. In addition to our OTTI facilities, we own a barge dock that can load or offload two barges of NGLs or refinery-grade propylene simultaneously at rates up to 5,000 barrels per hour. Our average combined NGL import and export volumes were 74 MBPD, 84 MBPD and 127 MBPD for the years ended December 31, 2008, 2007 and 2006, respectively.

Onshore Natural Gas Pipelines & Services

Our Onshore Natural Gas Pipelines & Services business segment includes approximately 18,346 miles of onshore natural gas pipeline systems that provide for the gathering and transmission of natural gas in Alabama, Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. We own two salt dome natural gas storage facilities located in Mississippi and lease natural gas storage facilities located in Texas and Louisiana. This segment also includes our natural gas marketing activities.

Onshore natural gas pipelines and related natural gas marketing. Our onshore natural gas pipeline systems provide for the gathering and transmission of natural gas from onshore developments, such as the San Juan, Barnett Shale, Permian, Piceance and Greater Green River supply basins in the Western U.S., and from offshore developments in the Gulf of Mexico through connections with offshore pipelines. Typically, these systems receive natural gas from producers, other pipelines or shippers through system interconnects and redeliver the natural gas to processing facilities, local gas distribution companies, industrial or municipal customers or to other onshore pipelines.

Certain of our onshore natural gas pipelines generate revenues from transportation agreements where shippers are billed a fee per unit of volume transported (typically in MMBtus) multiplied by the volume delivered. The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC. Certain of our onshore natural gas pipelines may also offer firm capacity reservation services whereby the shipper pays a contractually stated fee based on the level of capacity reserved in our pipelines whether or not the shipper actually ships the reserved quantity of natural gas. Intrastate natural gas pipelines (such as our Acadian Gas and Alabama Intrastate systems) may also purchase natural gas from producers and suppliers and resell such natural gas to customers such as electric utility companies, local natural gas distribution companies and industrial customers.

We entered the natural gas marketing business in 2001 when we acquired the Acadian Gas System. In 2007, we initiated an expansion of this marketing business to maximize the utilization of our portfolio of natural gas pipeline and storage assets. Our natural gas marketing activities generate revenues from the sale and delivery of natural gas obtained from (i) third party well-head purchases, (ii) our natural gas processing plants and (iii) the open market. In general, our natural gas sales contracts utilize market-based pricing and can incorporate pricing differentials for factors such as delivery location. We expect our natural gas marketing business to continue to expand in the future. Our consolidated revenues from this business were $3.10 billion, $1.48 billion and $1.10 billion for the years ended December 31, 2008, 2007 and 2006, respectively.

We are exposed to commodity price risk to the extent that we take title to natural gas volumes through our natural gas marketing activities or through certain contracts on our intrastate natural gas pipelines. In addition, our San Juan, Carlsbad and Jonah Gathering Systems and certain segments of our Texas Intrastate System provide aggregating and bundling services, in which we purchase and resell natural gas for certain small producers. Also, several of our gathering systems, while not providing marketing services, have some exposure to risks related to commodity prices through transportation arrangements with shippers. For example, revenues generated by approximately 94.0% of the natural gas volumes gathered on our San Juan Gathering System are calculated using a percentage of a regional price index for natural gas. We use commodity financial instruments from time to time to mitigate our exposure to risks related to commodity prices. For information regarding our use of commodity financial instruments, see “Commodity Risk Hedging Program” included under Item 7A of this annual report.

Underground natural gas storage. We own two underground salt dome natural gas storage facilities located near Hattiesburg, Mississippi that are ideally situated to serve the domestic Northeast, Mid-Atlantic and Southeast natural gas markets. On a combined basis, these facilities (our Petal Gas Storage (“Petal”) and Hattiesburg Gas Storage (“Hattiesburg”) locations) are capable of delivering in excess of 1.4 Bcf/d of natural gas into five interstate pipeline systems. We also lease underground salt dome natural gas storage caverns that serve markets in Texas and Louisiana.

The ability of salt dome storage caverns to handle high levels of injections and withdrawals of natural gas benefits customers who desire the ability to meet load swings and to cover major supply interruption events, such as hurricanes and temporary losses of production. High injection and withdrawal rates also allow customers to take advantage of periods of volatile natural gas prices and respond in situations where they have natural gas imbalance issues on pipelines connected to the storage facilities. Our salt dome storage facilities permit sustained periods of high natural gas deliveries, including the ability to quickly switch from full injection to full withdrawal.

Under our natural gas storage contracts, there are typically two components of revenues: (i) monthly demand payments, which are associated with storage capacity reservation and paid regardless of the customer's usage, and (ii) storage fees per unit of volume stored at our facilities.

Seasonality. Typically, our onshore natural gas pipelines experience higher throughput rates during the summer months as natural gas-fired power generation facilities increase output to meet residential and commercial demand for electricity for air conditioning. Higher throughput rates are also experienced in the winter months as natural gas is needed to fuel residential and commercial heating. Likewise, this seasonality also impacts the timing of injections and withdrawals at our natural gas storage facilities.

Competition. Within their market areas, our onshore natural gas pipelines compete with other onshore natural gas pipelines on the basis of price (in terms of transportation fees and/or natural gas selling prices), service and flexibility. Our competitive position within the onshore market is enhanced by our longstanding relationships with customers and the limited number of delivery pipelines connected (or capable of being economically connected) to the customers we serve.

Competition for natural gas storage is primarily based on location and the ability to deliver natural gas in a timely and reliable manner. Our natural gas storage facilities compete with other providers of natural gas storage, including other salt dome storage facilities and depleted reservoir facilities. We believe that the locations of our natural gas storage facilities allow us to compete effectively with other companies who provide natural gas storage services.

Properties. The following table summarizes the significant assets of our Onshore Natural Gas Pipelines & Services business segment at February 2, 2009.

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Approx. Net Capacity, Natural Gas (MMcf/d)	Gross Capacity (Bcf)
Onshore natural gas pipelines:					
Texas Intrastate System	Texas	100.0% (1)	7,860	5,535	
Piceance Basin Gathering System	Colorado	100.0%	79	1,600	
White River Hub	Colorado	50.0%	10	1,500	
San Juan Gathering System	New Mexico, Colorado	100.0%	6,065	1,200	
Acadian Gas System	Louisiana	Various (2)	1,042	1,149	
Jonah Gathering System	Wyoming	19.4%	714	455	
Carlsbad Gathering System	Texas, New Mexico	100.0%	919	220	
Alabama Intrastate System	Alabama	100.0%	408	200	
Encinal Gathering System	Texas	100.0%	449	143	
Other (6 systems) (3)	Texas, Mississippi	Various (4)	800	460	
Total miles			18,346		
Natural gas storage facilities:					
Petal	Mississippi	100.0%			16.6
Hattiesburg	Mississippi	100.0%			2.1
Wilson	Texas	Leased (5)			6.8
Acadian	Louisiana	Leased (6)			1.7
Total gross capacity					27.2

(1) In general, our consolidated ownership of this system is 100.0% through interests held by EPO and Duncan Energy Partners. However, we own and operate a consolidated 50.0% undivided interest in the 641-mile Channel pipeline system, which is a component of the Texas Intrastate System. The remaining 50.0% is owned by affiliates of Energy Transfer Equity. In addition, we own less than a 100.0% undivided interest in certain segments of the Enterprise Texas pipeline system.

(2) Reflects consolidated ownership of Acadian Gas by EPO (34.0%) and Duncan Energy Partners (66.0%). Also includes the 49.5% equity investment that Acadian Gas has in the Evangeline pipeline.

(3) Includes the Delmita, Big Thicket, Indian Springs and Canales gathering systems located in Texas and the Petal and Hattiesburg pipelines located in Mississippi. The Delmita and Big Thicket gathering systems are integral parts of our natural gas processing operations, the results of operations and assets of which are accounted for under our NGL Pipelines & Services business segment. We acquired the Canales gathering system in connection with the Encinal acquisition in July 2006. The Petal and Hattiesburg pipelines are integral components of our natural gas storage operations.

(4) We own 100.0% of these assets with the exception of the Indian Springs system, in which we own an 80.0% undivided interest through a consolidated subsidiary. Our 100.0% interest in Big Thicket reflects consolidated ownership by EPO (34.0%) and Duncan Energy Partners (66.0%).

(5) We hold this facility under an operating lease that expires in January 2028.

(6) We hold this facility under an operating lease that expires in December 2012.

On a weighted-average basis, aggregate utilization rates for our onshore natural gas pipelines were approximately 65.5%, 63.5% and 70.9% during the years ended December 31, 2008, 2007 and 2006, respectively. The utilization rate for 2008 excludes the White River Hub, which commenced operations during December 2008 and continues to experience a ramp-up in volumes. The utilization rate for 2007 excludes our Piceance Creek Gathering System, which operated at an average utilization rate of 24.3% during 2007 as volumes ramped-up on this system. Generally, our utilization rates reflect the periods in which we owned an interest in such assets, or, for recently constructed assets, since the dates such assets were placed into service.

The following information highlights the general use of each of our principal onshore natural gas pipelines and storage facilities. We operate our onshore natural gas pipelines and storage facilities with the exception of the White River Hub and small segments of the Texas Intrastate System.

- The *Texas Intrastate System* gathers and transports natural gas from supply basins in Texas (from both onshore and offshore sources) to local gas distribution companies and electric generation and industrial and municipal consumers as well as to connections with intrastate and interstate pipelines. The Texas Intrastate System is comprised of the 6,547-mile Enterprise Texas pipeline system, the 641-mile Channel pipeline system, the 465-mile Waha gathering system and the 207-

mile TPC Offshore gathering system. The leased Wilson natural gas storage facility is an integral part of the Texas Intrastate System. The Enterprise Texas pipeline system includes a 263-mile pipeline we lease from an affiliate of ETP. Collectively, the Texas Intrastate System serves important natural gas producing regions and commercial markets in Texas, including Corpus Christi, the San Antonio/Austin area, the Beaumont/Orange area and the Houston area, including the Houston Ship Channel industrial market.

The 178-mile Sherman Extension of our Texas Intrastate System is scheduled for final completion in March 2009. The Sherman Extension is capable of transporting up to 1.1 Bcf/d of natural gas from the prolific Barnett Shale production basin in North Texas and provides producers with interconnects with third party interstate pipelines having access to markets outside of Texas. Customers, including EPO, have contracted for an aggregate 1.0 Bcf/d of the capacity of the Sherman Extension.

In late 2008, we began design of the 40-mile Trinity River Basin Extension, which is expected to be completed in the fourth quarter of 2009. The Trinity River Basin Extension will be capable of transporting up to 1.0 Bcf/d of natural gas and will provide producers in the Barnett Shale production basin with additional takeaway capacity. We are also constructing a new storage cavern adjacent to the leased Wilson natural gas storage facility that is expected to be completed in 2010. When completed, this new cavern is expected to provide us with an additional 5.0 Bcf of useable natural gas storage capacity.

We contributed equity interests in our subsidiaries that own the Texas Intrastate System to Duncan Energy Partners effective December 8, 2008. As a result, Duncan Energy Partners owns a 51.0% voting equity interest in the entity that owns the Enterprise Texas pipeline system, the Channel pipeline system and the Wilson storage facility. Also, Duncan Energy Partners owns a 66.0% voting equity interest in the entity that owns the Waha gathering system and the TPC Offshore gathering system. We own, through our other subsidiaries, the remaining equity interests in these entities. For additional information regarding this transaction, see "Other Items – Duncan Energy Partners Transactions" included under Item 7 of this annual report.

- The *Piceance Basin Gathering System* consists of the 48-mile Piceance Creek and the 31-mile Great Divide gathering systems located in the Piceance Basin of northwestern Colorado. We acquired the Piceance Creek gathering system from EnCana Oil & Gas USA ("EnCana") in December 2006 and subsequently placed this asset in-service during January 2007. We acquired the Great Divide gathering system from EnCana in December 2008. The Great Divide gathering system gathers natural gas from the southern portion of the Piceance basin, including EnCana's Mamm Creek field, to our Piceance Creek gathering system. The Piceance Creek gathering system extends from a connection with the Great Divide gathering system to the Meeker facility. For additional information regarding our acquisition of the Great Divide system, see Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

- The *White River Hub* is a FERC-regulated interstate natural gas transmission system designed to provide natural gas transportation and hub services. The White River Hub connects to six interstate natural gas pipelines in northwest Colorado and has a gross capacity of 3.0 Bcf/d of natural gas (1.5 Bcf/d net to our interest). White River Hub began service in December 2008.

- The *San Juan Gathering System* serves natural gas producers in the San Juan Basin of New Mexico and Colorado. This system gathers natural gas from approximately 10,813 producing wells in the San Juan Basin and delivers the natural gas to natural gas processing facilities, including our Chaco facility.

- The *Acadian Gas System* purchases, transports, stores and sells natural gas in Louisiana. The Acadian Gas System is comprised of the 577-mile Cypress pipeline, the 438-mile Acadian pipeline and the 27-mile Evangeline pipeline. The leased Acadian natural gas storage facility is an integral part of the Acadian Gas System.

- The *Jonah Gathering System* is located in the Greater Green River Basin of southwestern Wyoming. This system gathers natural gas from the Jonah and Pinedale fields for delivery to regional natural gas processing plants, including our Pioneer facility, and major interstate pipelines. Our ownership in this gathering system is through our 19.4% equity method investment in Jonah Gas Gathering Company, which we acquired from TEPPCO in August 2006. We completed the Phase V expansion of the Jonah Gathering System in June 2008.

- The C*arlsbad Gathering System* gathers natural gas from wells in the Permian Basin region of Texas and New Mexico and delivers natural gas into the El Paso Natural Gas, Transwestern and Oasis pipelines.

- The *Alabama Intrastate System* mainly gathers coal bed methane from wells in the Black Warrior Basin in Alabama. This system is also involved in the purchase, transportation and sale of natural gas.

- The *Encinal Gathering System* gathers natural gas from the Olmos and Wilcox formations in south Texas and delivers into our Texas Intrastate System, which delivers the natural gas to our south Texas facilities for processing. We acquired this gathering system in connection with the Encinal acquisition in July 2006.

- The *Petal* and *Hattiesburg* underground storage facilities are strategically situated to serve the domestic Northeast, Mid-Atlantic and Southeast natural gas markets and are capable of delivering in excess of 1.4 Bcf/d of natural gas into five interstate pipeline systems. We placed a new natural gas storage cavern at our Petal facility into service during the third quarter of 2008. The new cavern has a total of 9.1 Bcf of storage capacity which represents 5.9 Bcf of FERC certificated working gas capacity and approximately 3.2 Bcf of base gas requirements needed to support minimum pressures.

Offshore Pipelines & Services

Our Offshore Pipelines & Services business segment includes (i) approximately 1,544 miles of offshore natural gas pipelines strategically located to serve production areas including some of the most active drilling and development regions in the Gulf of Mexico, (ii) approximately 909 miles of offshore Gulf of Mexico crude oil pipeline systems and (iii) six multi-purpose offshore hub platforms located in the Gulf of Mexico with crude oil or natural gas processing capabilities.

Offshore natural gas pipelines. Our offshore natural gas pipeline systems provide for the gathering and transmission of natural gas from production developments located in the Gulf of Mexico, primarily offshore Louisiana and Texas. Typically, these systems receive natural gas from producers, other pipelines and shippers through system interconnects and transport the natural gas to various downstream pipelines, including major interstate transmission pipelines that access multiple markets in the eastern half of the United States.

Our revenues from offshore natural gas pipelines are derived from fee-based agreements and are typically based on transportation fees per unit of volume transported (generally in MMBtus) multiplied by the volume delivered. These transportation agreements tend to be long-term in nature, often involving life-of-reserve commitments with firm and interruptible components. We do not take title to the natural gas volumes that are transported on our natural gas pipeline systems; rather, the shipper retains title and the associated commodity price risk.

Offshore oil pipelines. We own interests in several offshore oil pipeline systems, which are located in the vicinity of oil-producing areas in the Gulf of Mexico. Typically, these systems receive crude oil from offshore production developments, other pipelines or shippers through system interconnects and deliver the crude oil to either onshore locations or to other offshore interconnecting pipelines.

The majority of revenues from our offshore crude oil pipelines are generated based upon a transportation fee per unit of volume (typically in barrels) multiplied by the volume delivered to the customer. A substantial portion of the revenues generated by our offshore crude oil pipeline systems are attributable to long-term transportation agreements with producers. The revenues we earn for our services are dependent on the volume of crude oil to be delivered and the level of fees charged to customers.

Offshore platforms. We have ownership interests in six multi-purpose offshore hub platforms located in the Gulf of Mexico with crude oil and/or natural gas processing capabilities. Offshore platforms are critical components of the energy-related infrastructure in the Gulf of Mexico, supporting drilling and producing operations, and therefore play a key role in the overall development of offshore oil and natural gas reserves. Platforms are used to: (i) interconnect with the offshore pipeline grid; (ii) provide an efficient means to perform pipeline maintenance; (iii) locate compression, separation and production handling and other facilities; (iv) conduct drilling operations during the initial development phase of an oil and natural gas property; and (v) process off-lease production.

Revenues from offshore platform services generally consist of demand payments and commodity charges. Demand fees represent charges to customers served by our offshore platforms regardless of the volume the customer delivers to the platform. Revenues from commodity charges are based on a fixed-fee per unit of volume delivered to the platform (typically per MMcf of natural gas or per barrel of crude oil) multiplied by the total volume of each product delivered. Contracts for platform services often include both demand payments and commodity charges, but demand payments generally expire after a contractually fixed period of time and in some instances may be subject to cancellation by customers. Our Independence Hub and Marco Polo offshore platforms earn a significant amount of demand revenues. The Independence Hub platform will earn \$54.6 million of demand revenues annually through March 2012. The Marco Polo platform will earn \$2.1 million of demand revenues monthly through March 2009.

Seasonality. Our offshore operations exhibit little to no effects of seasonality; however, they may be affected by weather events such as hurricanes and tropical storms in the Gulf of Mexico.

Competition. Within their market areas, our offshore natural gas and oil pipelines compete with other pipelines (both regulated and unregulated systems) primarily on the basis of price (in terms of transportation fees), available capacity and connections to downstream markets. To a limited extent, our competition includes other offshore pipeline systems, built, owned and operated by producers to handle their own production and, as capacity is available, production for others. We compete with other platform service providers on the basis of proximity and access to existing reserves and pipeline systems, as well as costs and rates. Furthermore, our competitors may possess greater capital resources than we have available, which could enable them to address business opportunities more quickly than us.

Properties. The following table summarizes the significant assets of our Offshore Pipelines & Services business segment at February 2, 2009, all of which are located in the Gulf of Mexico primarily offshore Louisiana and Texas.

Description of Asset	Our Ownership Interest	Length (Miles)	Water Depth (Feet)	Approximate Net Capacity Natural Gas (MMcf/d)	Approximate Net Capacity Crude Oil (MPBD)
Offshore natural gas pipelines:					
High Island Offshore System	100.0%	291		1,800	
Viosca Knoll Gathering System	100.0%	162		1,000	
Independence Trail	100.0%	134		1,000	
Green Canyon Laterals	Various (1)	94		605	
Phoenix Gathering System	100.0%	77		450	
Falcon Natural Gas Pipeline	100.0%	14		400	
Anaconda Gathering System	100.0%	137		300	
Manta Ray Offshore Gathering System (2)	25.7%	250		206	
Nautilus System (2)	25.7%	101		154	
VESCO Gathering System (3)	13.1%	260		105	
Nemo Gathering System (4)	33.9%	24		102	
Total miles		1,544			
Offshore crude oil pipelines:					
Cameron Highway Oil Pipeline (5)	50.0%	374			250
Poseidon Oil Pipeline System (6)	36.0%	367			144
Allegheny Oil Pipeline	100.0%	43			140
Marco Polo Oil Pipeline	100.0%	37			120
Constitution Oil Pipeline	100.0%	67			80
Typhoon Oil Pipeline	100.0%	17			80
Tarantula Oil Pipeline	100.0%	4			30
Total miles		909			
Offshore platforms:					
Independence Hub	80.0%		8,000	800	NA
Marco Polo (7)	50.0%		4,300	150	60
Viosca Knoll 817	100.0%		671	145	5
Garden Banks 72	50.0%		518	38	18
East Cameron 373	100.0%		441	195	3
Falcon Nest	100.0%		389	400	3

(1) Our ownership interests in the Green Canyon Laterals ranges from 2.7% to 100.0%.
(2) Our ownership interest in these pipelines is held indirectly through our equity method investment in Neptune Pipeline Company, L.L.C. ("Neptune").
(3) Our ownership interest in this system is held indirectly through our equity method investment in VESCO.
(4) Our ownership interest in this pipeline is held indirectly through our equity method investment in Nemo Gathering Company, LLC ("Nemo").
(5) Our 50.0% joint control ownership interest in this pipeline is held indirectly through our equity method investment in Cameron Highway Oil Pipeline Company ("Cameron Highway").
(6) Our ownership interest in this pipeline is held indirectly through our equity method investment in Poseidon Oil Pipeline Company, LLC. ("Poseidon").
(7) Our 50.0% joint control ownership interest in this platform is held indirectly through our equity method investment in Deepwater Gateway, L.L.C. ("Deepwater Gateway").

We operate our offshore natural gas pipelines, with the exception of the VESCO Gathering System, Manta Ray Offshore Gathering System, Nautilus System, Nemo Gathering System and certain components of the Green Canyon Laterals. On a weighted-average basis, aggregate utilization rates for our offshore natural gas pipelines were approximately 22.0%, 24.1% and 25.9% during the years ended December 31, 2008, 2007 and 2006, respectively. For recently constructed assets (e.g., Independence Trail), utilization rates reflect the periods since the dates such assets were placed into service.

The following information highlights the general use of each of our principal Gulf of Mexico offshore natural gas pipelines.

- The *High Island Offshore System* ("HIOS") transports natural gas from producing fields located in the Galveston, Garden Banks, West Cameron, High Island and East Breaks areas of the Gulf of

Mexico to the ANR pipeline system, Tennessee Gas Pipeline and the U-T Offshore System. The HIOS pipeline system includes eight pipeline junction and service platforms. This system also includes the 86-mile East Breaks System that connects HIOS to the Hoover-Diana deepwater platform located in Alaminos Canyon Block 25.

- The *Viosca Knoll Gathering System* transports natural gas from producing fields located in the Main Pass, Mississippi Canyon and Viosca Knoll areas of the Gulf of Mexico to several major interstate pipelines, including the Tennessee Gas, Columbia Gulf, Southern Natural, Transco, Dauphin Island Gathering System and Destin Pipelines.

- The *Independence Trail* natural gas pipeline transports natural gas from our Independence Hub platform to the Tennessee Gas Pipeline. Natural gas transported on the Independence Trail pipeline originates from production fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas of the Gulf of Mexico. This pipeline includes one pipeline junction platform at West Delta 68. We completed construction of the Independence Trail natural gas pipeline in 2006 and, in July 2007, the pipeline received its first production from deepwater wells connected to the Independence Hub platform.

- The *Green Canyon Laterals* consist of 15 pipeline laterals (which are extensions of natural gas pipelines) that transport natural gas to downstream pipelines, including HIOS.

- The *Phoenix Gathering System* connects the Red Hawk platform located in the Garden Banks area of the Gulf of Mexico to the ANR pipeline system.

- The *Falcon Natural Gas Pipeline* delivers natural gas processed at our Falcon Nest platform to a connection with the Central Texas Gathering System located on the Brazos Addition Block 133 platform.

- The *Anaconda Gathering System* connects our Marco Polo platform and the third-party owned Constitution platform to the ANR pipeline system. The Anaconda Gathering System includes our wholly owned Typhoon, Marco Polo and Constitution natural gas pipelines. The Constitution natural gas pipeline serves the Constitution and Ticonderoga fields located in the central Gulf of Mexico.

- The *Manta Ray Offshore Gathering System* transports natural gas from producing fields located in the Green Canyon, Southern Green Canyon, Ship Shoal, South Timbalier and Ewing Bank areas of the Gulf of Mexico to numerous downstream pipelines, including our Nautilus System.

- The *Nautilus System* connects our Manta Ray Offshore Gathering System to our Neptune natural gas processing plant on the Louisiana gulf coast.

- The *VESCO Gathering System* is a regulated natural gas pipeline system associated with the Venice natural gas processing plant in Louisiana. This pipeline is an integral part of the natural gas processing operations of VESCO.

- The *Nemo Gathering System* transports natural gas from Green Canyon developments to an interconnect with our Manta Ray Offshore Gathering System.

The following information highlights the general use of each of our principal Gulf of Mexico offshore crude oil pipelines, all of which we operate. On a weighted-average basis, aggregate utilization rates for our offshore crude oil pipelines were approximately 20.1%, 19.3% and 18.1% during the years ended December 31, 2008, 2007 and 2006, respectively.

- The *Cameron Highway Oil Pipeline* gathers crude oil production from deepwater areas of the Gulf of Mexico, primarily the South Green Canyon area, for delivery to refineries and terminals in southeast Texas. This pipeline includes one pipeline junction platform.

- The *Poseidon Oil Pipeline System* gathers production from the outer continental shelf and deepwater areas of the Gulf of Mexico for delivery to onshore locations in south Louisiana. This system includes one pipeline junction platform.

- The *Allegheny Oil Pipeline* connects the Allegheny and South Timbalier 316 platforms in the Green Canyon area of the Gulf of Mexico with our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.

- The *Marco Polo Oil Pipeline* transports crude oil from our Marco Polo platform to an interconnect with our Allegheny Oil Pipeline in Green Canyon Block 164.

- The *Constitution Oil Pipeline* serves the Constitution and Ticonderoga fields located in the central Gulf of Mexico. The Constitution Oil Pipeline connects with our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System at a pipeline junction platform.

In October 2006, we announced the execution of definitive agreements with producers to construct, own and operate an oil export pipeline (the “Shenzi Oil Pipeline”) that will provide firm gathering services from the BHP Billiton Plc-operated Shenzi production field located in the South Green Canyon area of the central Gulf of Mexico. The Shenzi Oil Pipeline is expected to commence operations during the second quarter of 2009. In August 2008, we, together with TEPPCO and Oiltanking Holding Americas, Inc., announced the formation of the Texas Offshore Port System, a joint venture to design, construct, operate and own a Texas offshore crude oil port and related pipeline and storage system that would facilitate delivery of waterborne crude oil cargoes to refining centers located along the upper Texas Gulf Coast. For information regarding these projects, see “Liquidity and Capital Resources – Significant Ongoing Growth Capital Projects” included under Item 7 of this annual report.

The following information highlights the general use of each of our principal Gulf of Mexico offshore platforms. We operate these offshore platforms with the exception of the Independence Hub, Marco Polo and East Cameron 373 platforms.

On a weighted-average basis, utilization rates with respect to natural gas processing capacity of our offshore platforms were approximately 36.5%, 28.6% and 17.2% during the years ended December 31, 2008, 2007 and 2006, respectively. Likewise, utilization rates for our offshore platforms were approximately 16.9%, 26.1% and 19.2%, respectively, in connection with platform crude oil processing capacity. For recently constructed assets (e.g., Independence Hub), these rates reflect the periods since the dates such assets were placed into service. In addition to the offshore platforms we identified in the preceding table, we own or have an ownership interest in fourteen pipeline junction and service platforms. Our pipeline junction and service platforms do not have processing capacity.

- The *Independence Hub* platform is located in Mississippi Canyon Block 920. This platform processes natural gas gathered from deepwater production fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas of the Gulf of Mexico. We successfully installed the Independence Hub platform and began earning demand revenues in March 2007. In July 2007, the Independence Hub platform received first production from deepwater wells connected to the platform.

- The *Marco Polo* platform, which is located in Green Canyon Block 608, processes crude oil and natural gas from the Marco Polo, K2, K2 North and Genghis Khan fields. These fields are located in the South Green Canyon area of the Gulf of Mexico.

- The *Viosca Knoll 817* platform is centrally located on our Viosca Knoll Gathering System. This platform primarily serves as a base for gathering deepwater production in the area, including the Ram Powell development.

- The *Garden Banks 72* platform serves as a base for gathering deepwater production from the Garden Banks Block 161 development and the Garden Banks Block 378 and 158 leases. This platform also serves as a junction platform for our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.

- The *East Cameron 373* platform serves as the host for East Cameron Block 373 production and also processes production from Garden Banks Blocks 108, 152, 197, 200 and 201.

- The *Falcon Nest* platform, which is located in the Mustang Island Block 103 area of the Gulf of Mexico, currently processes natural gas from the Falcon field.

Petrochemical Services

Our Petrochemical Services business segment primarily includes two propylene fractionation facilities, an isomerization complex, and an octane additive production facility. This segment also includes approximately 649 miles of petrochemical pipeline systems.

<u>*Propylene fractionation*</u>*.* Our propylene fractionation business consists primarily of two propylene fractionation facilities located in Texas and Louisiana and propylene pipeline systems aggregating approximately 579 miles. These operations also include an export facility located on the Houston Ship Channel and our petrochemical marketing activities.

In general, propylene fractionation plants separate refinery grade propylene (a mixture of propane and propylene) into either polymer grade propylene or chemical grade propylene along with by-products of propane and mixed butane. Polymer grade and chemical grade propylene can also be produced as a by-product of olefin (ethylene) production. The demand for polymer grade propylene primarily relates to the manufacture of polypropylene, which has a variety of end uses, including packaging film, fiber for carpets and upholstery and molded plastic parts for appliance, automotive, houseware and medical products. Chemical grade propylene is a basic petrochemical used in the manufacturing of plastics, synthetic fibers and foams.

Results of operations for our polymer grade propylene plants are generally dependent upon toll processing arrangements and petrochemical marketing activities. These processing arrangements typically include a base-processing fee per gallon (or other unit of measurement) subject to adjustment for changes in natural gas, electricity and labor costs, which are the primary costs of propylene fractionation and isomerization operations. Our petrochemical marketing activities generate revenues from the sale and delivery of products obtained through our processing activities and purchases from third parties on the open market. In general, we sell our petrochemical products at market-related prices, which may include pricing differentials for such factors as delivery location.

As part of our petrochemical marketing activities, we have several long-term polymer grade propylene sales agreements. To meet our petrochemical marketing obligations, we have entered into several agreements to purchase refinery grade propylene. To limit the exposure of our petrochemical marketing activities to price risk, we attempt to match the timing and price of our feedstock purchases with those of the sales of end products.

<u>*Isomerization*</u>*.* Our isomerization business includes three butamer reactor units and eight associated deisobutanizer units located in Mont Belvieu, Texas, which comprise the largest commercial isomerization complex in the United States. In addition, this business includes a 70-mile pipeline system used to transport high-purity isobutane from Mont Belvieu, Texas to Port Neches, Texas.

Our commercial isomerization units convert normal butane into mixed butane, which is subsequently fractionated into isobutane, high purity isobutane and residual normal butane. The primary uses of isobutane are currently for the production of propylene oxide, isooctane and alkylate for motor gasoline. The demand for commercial isomerization services depends upon the industry’s requirements for high purity isobutane and isobutane in excess of naturally occurring isobutane produced from NGL fractionation and refinery operations.

The results of operation of this business are generally dependent upon the volume of normal and mixed butanes processed and the level of toll processing fees charged to customers. Our isomerization facility provides processing services to meet the needs of third-party customers and our other businesses, including our NGL marketing activities and octane additive production facility.

Octane enhancement. We own and operate an octane additive production facility located in Mont Belvieu, Texas designed to produce isooctane, which is an additive used in reformulated motor gasoline blends to increase octane, and isobutylene. The facility produces isooctane and isobutylene using feedstock of high-purity isobutane, which is supplied by our isomerization units. Prior to mid-2005, the facility produced methyl tertiary butyl ether ("MTBE"). We modified the facility to produce isooctane and isobutylene. Depending on the outcome of various factors, the facility may be further modified in the future to produce alkylate, another motor gasoline additive.

Seasonality. Overall, the propylene fractionation business exhibits little seasonality. Our isomerization operations experience slightly higher demand in the spring and summer months due to the demand for isobutane-based fuel additives used in the production of motor gasoline. Likewise, isooctane prices have been stronger during the April to September period of each year, which corresponds with the summer driving season.

Competition. We compete with numerous producers of polymer grade propylene, which include many of the major refiners and petrochemical companies located along the Gulf Coast. Generally, the propylene fractionation business competes in terms of the level of toll processing fees charged and access to pipeline and storage infrastructure. Our petrochemical marketing activities encounter competition from fully integrated oil companies and various petrochemical companies. Our petrochemical marketing competitors have varying levels of financial and personnel resources and competition generally revolves around price, service, logistics and location.

With respect to our isomerization operations, we compete primarily with facilities located in Kansas, Louisiana and New Mexico. Competitive factors affecting this business include the level of toll processing fees charged, the quality of isobutane that can be produced and access to pipeline and storage infrastructure. We compete with other octane additive manufacturing companies primarily on the basis of price.

Properties. The following table summarizes the significant assets of our Petrochemical Services segment at February 2, 2009, all of which we operate.

Description of Asset	Location(s)	Our Ownership Interest	Net Plant Capacity (MBPD)	Total Plant Capacity (MBPD)	Length (Miles)
Propylene fractionation facilities:					
Mont Belvieu (six units)	Texas	Various (1)	73	87	
BRPC	Louisiana	30.0% (2)	7	23	
Total capacity			80	110	
Isomerization facility:					
Mont Belvieu (3)	Texas	100.0%	116	116	
Petrochemical pipelines:					
Lou-Tex and Sabine Propylene	Texas, Louisiana	100.0% (4)			284
Texas City RGP Gathering System	Texas	100.0%			86
Lake Charles	Texas, Louisiana	50.0%			81
Others (5 systems) (5)	Texas	Various (6)			198
Total miles					649
Octane additive production facilities:					
Mont Belvieu (7)	Texas	100.0%	12	12	

(1) We own a 54.6% interest and lease the remaining 45.4% of a unit having 17 MBPD of plant capacity. We own a 66.7% interest in three additional units having an aggregate 41 MBPD of total plant capacity. We own 100.0% of the remaining two units, which have 14 MBPD and 15 MBPD of plant capacity, respectively.
(2) Our ownership interest in this facility is held indirectly through our equity method investment in Baton Rouge Propylene Concentrator LLC ("BRPC").
(3) On a weighted-average basis, utilization rates for this facility were approximately 74.1%, 77.6% and 69.8% during the years ended December 31, 2008, 2007 and 2006, respectively.
(4) Reflects consolidated ownership of these pipelines by EPO (34.0%) and Duncan Energy Partners (66.0%).
(5) Includes our Texas City PGP Delivery System and Port Neches, La Porte, Port Arthur and Bayport petrochemical pipelines.
(6) We own 100.0% of these pipelines with the exception of the 17-mile La Porte pipeline, in which we hold an aggregate 50.0% indirect interest through our equity method investments in La Porte Pipeline Company L.P. and La Porte Pipeline GP, L.L.C.
(7) On a weighted-average basis, utilization rates for this facility were approximately 58.3% during each of the years ended December 31, 2008, 2007 and 2006, respectively.

We produce polymer grade propylene at our Mont Belvieu location and chemical grade propylene at our BRPC facility. The primary purpose of the BRPC unit is to fractionate refinery grade propylene produced by an affiliate of Exxon Mobil Corporation into chemical grade propylene. The production of polymer grade propylene from our Mont Belvieu facility is primarily used in our petrochemical marketing activities. On a weighted-average basis, aggregate utilization rates of our propylene fractionation facilities were approximately 72.2%, 86.0% and 86.2% during the years ended December 31, 2008, 2007 and 2006, respectively. This business segment also includes an above-ground polymer grade propylene storage and export facility located in Seabrook, Texas. This facility can load vessels at rates up to 5,000 barrels per hour.

The Lou-Tex Propylene pipeline is used to transport chemical grade propylene from Sorrento, Louisiana to Mont Belvieu, Texas. The Sabine pipeline is used to transport polymer grade propylene from Port Arthur, Texas to a pipeline interconnect in Cameron Parish, Louisiana.

The maximum number of barrels that our petrochemical pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon the mix of products to be shipped and demand levels at various delivery points, the exact capacities of our petrochemical pipelines cannot be determined. We measure the utilization rates of such pipelines in terms of net throughput (i.e., on a net basis in accordance with our ownership interest). Total net throughput volumes for these pipelines were 108 MBPD, 105 MBPD and 97 MBPD during the years ended December 31, 2008, 2007 and 2006, respectively.

Title to Properties

Our real property holdings fall into two basic categories: (i) parcels that we and our unconsolidated affiliates own in fee (e.g., we own the land upon which our Mont Belvieu NGL fractionator is constructed) and (ii) parcels in which our interests and those of our unconsolidated affiliates are derived from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. The fee sites upon which our significant facilities are located have been owned by us or our predecessors in title for many years without any material challenge known to us relating to title to the land upon which the assets are located, and we believe that we have satisfactory title to such fee sites. We and our unconsolidated affiliates have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our rights pursuant to any material lease, easement, right-of-way, permit or license, and we believe that we have satisfactory rights pursuant to all of our material leases, easements, rights-of-way, permits and licenses.

Capital Spending

We are committed to the long-term growth and viability of Enterprise Products Partners. Part of our business strategy involves expansion through business combinations, growth capital projects and investments in joint ventures. We believe we are positioned to continue to grow our system of assets through the construction of new facilities and to capitalize on expected future production increases from areas such as the Piceance Basin of western Colorado, the Greater Green River Basin in Wyoming, the Barnett Shale in North Texas and the deepwater Gulf of Mexico. For a discussion of our capital spending program, see "Liquidity and Capital Resources - Capital Spending" included under Item 7 of this annual report.

Weather-Related Risks

In the third quarter of 2008, our onshore and offshore facilities located along the Gulf Coast of Texas and Louisiana were adversely impacted by Hurricanes Gustav and Ike. The disruptions in natural gas, NGL and crude oil production caused by these storms resulted in decreased volumes for some of our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which, in turn, caused a decrease in gross operating margin from these operations. See Note 21 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for more information regarding significant risks and uncertainties.

Regulation

Interstate Pipelines

Liquids Pipelines. Certain of our crude oil and NGL pipeline systems (collectively referred to as "liquids pipelines") are interstate common carrier pipelines subject to regulation by the FERC under the Interstate Commerce Act ("ICA") and the Energy Policy Act of 1992 ("Energy Policy Act"). The ICA prescribes that interstate tariffs must be just and reasonable and must not be unduly discriminatory or confer any undue preference upon any shipper. FERC regulations require that interstate oil pipeline transportation rates and terms of service be filed with the FERC and posted publicly.

The ICA permits interested persons to challenge proposed new or changed rates or rules and authorizes the FERC to investigate such changes and to suspend their effectiveness for a period of up to seven months. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it may require the carrier to refund the revenues in excess of the prior tariff during the term of the investigation. The FERC may also investigate, upon complaint or on its own motion, rates and related rules that are already in effect and may order a carrier to change them prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of its complaint.

The Energy Policy Act deems just and reasonable (i.e., deems “grandfathered”) liquids pipeline rates that (i) were in effect for the twelve months preceding enactment and (ii) that had not been subject to complaint, protest or investigation. Some, but not all, of our interstate liquids pipeline rates are considered grandfathered under the Energy Policy Act. Certain other rates for our interstate liquids pipeline services are charged pursuant to a FERC-approved indexing methodology, which allows a pipeline to charge rates up to a prescribed ceiling that changes annually based on the change from year-to-year in the Producer Price Index for finished goods (“PPI”). A rate increase within the indexed rate ceiling is presumed to be just and reasonable unless a protesting party can demonstrate that the rate increase is substantially in excess of the pipeline’s costs. Effective March 21, 2006, the FERC concluded that for the five-year period commencing July 1, 2006, liquids pipelines charging indexed rates may adjust their indexed ceilings annually by the PPI plus 1.3%.

As an alternative to using the indexing methodology, interstate liquids pipelines may elect to support rate filings by using a cost-of-service methodology, competitive market showings (“Market-Based Rates”) or agreements with all of the pipeline’s shippers that the rate is acceptable.

Because of the complexity of ratemaking, the lawfulness of any rate is never assured. Prescribed rate methodologies for approving regulated tariff rates may limit our ability to set rates based on our actual costs or may delay the use of rates reflecting higher costs. Changes in the FERC’s methodology for approving rates could adversely affect us. In addition, challenges to our tariff rates could be filed with the FERC and decisions by the FERC in approving our regulated rates could adversely affect our cash flow. We believe the transportation rates currently charged by our interstate common carrier liquids pipelines are in accordance with the ICA. However, we cannot predict the rates we will be allowed to charge in the future for transportation services by such pipelines.

The Lou-Tex Propylene and Sabine Propylene pipelines are interstate common carrier pipelines regulated under the ICA by the Surface Transportation Board (“STB”). If the STB finds that a carrier’s rates are not just and reasonable or are unduly discriminatory or preferential, it may prescribe a reasonable rate. In determining a reasonable rate, the STB will consider, among other factors, the effect of the rate on the volumes transported by that carrier, the carrier’s revenue needs and the availability of other economic transportation alternatives.

The STB does not need to provide rate relief unless shippers lack effective competitive alternatives. If the STB determines that effective competitive alternatives are not available and a pipeline holds market power, then we may be required to show that our rates are reasonable.

Mid-America Pipeline Company, LLC (“Mid-America”) is currently involved in a rate case before the FERC. The case primarily involves shipper protests of rate increases on Mid-America's Conway North pipeline filed on March 31, 2005 and March 31, 2006. A hearing before an Administrative Law Judge began on October 2, 2007 and culminated with an initial decision on September 3, 2008. Briefs on Exceptions were filed October 31, 2008, with Briefs Opposing Exceptions filed on January 8, 2009. The matter is presently pending before the FERC, with a decision expected to be issued in the second half of 2009. We are unable to predict the outcome of this litigation.

Natural Gas Pipelines. Our interstate natural gas pipelines and storage facilities that provide services in interstate commerce are regulated by the FERC under the Natural Gas Act of 1938 (“NGA”). Under the NGA, the rates for service on these interstate facilities must be just and reasonable and not unduly discriminatory. We operate these interstate facilities pursuant to tariffs which set forth rates and terms and conditions of service. These tariffs must be filed with and approved by the FERC pursuant to its regulations and orders. Our tariff rates may be lowered on a prospective basis only by the FERC if it finds, on its own initiative or as a result of challenges to the rates by third parties, that they are unjust, unreasonable or otherwise unlawful. Unless the FERC grants specific authority to charge market-based rates, our rates are derived and charged based on a cost-of-service methodology.

The FERC’s authority over companies that provide natural gas pipeline transportation or storage services in interstate commerce also includes: (i) certification, construction, and operation of certain new facilities; (ii) the acquisition, extension, disposition or abandonment of such facilities; (iii) the maintenance of accounts and records; (iv) the initiation, extension and termination of regulated services; and (v) various other matters. The FERC's rules require interstate pipelines and their affiliates to adhere to Standards of Conduct that, among other things, require that transmission employees function independently of marketing employees. The Energy Policy Act of 2005 amended the NGA to add an anti-manipulation provision. Pursuant to that act, the FERC established rules prohibiting energy market manipulation. A violation of these rules may subject us to civil penalties, disgorgement of unjust profits, or appropriate non-monetary remedies imposed by the FERC. In addition, the Energy Policy Act of 2005 amended the NGA and the Natural Gas Policy Act of 1978 ("NGPA") to increase civil and criminal penalties for any violation of the NGA, NGPA and any rules, regulations or orders of the FERC up to $1.0 million per day per violation.

Offshore Pipelines. Our offshore natural gas gathering pipelines and crude oil pipeline systems are subject to federal regulation under the Outer Continental Shelf Lands Act, which requires that all pipelines operating on or across the outer continental shelf provide nondiscriminatory transportation service.

Intrastate Pipelines

Liquids Pipelines. Certain of our pipeline systems operate within a single state and provide intrastate pipeline transportation services. These pipeline systems are subject to various regulations and statutes mandated by state regulatory authorities. Although the applicable state statutes and regulations vary, they generally require that intrastate pipelines publish tariffs setting forth all rates, rules and regulations applying to intrastate service, and generally require that pipeline rates and practices be reasonable and nondiscriminatory. Shippers may also challenge our intrastate tariff rates and practices on our pipelines. Our intrastate liquids pipelines are subject to regulation in many states, including Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas.

Natural Gas Pipelines. Our intrastate natural gas pipelines are subject to regulation in many states, including Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas. Certain of our intrastate natural gas pipelines are also subject to limited regulation by the FERC under the NGPA because they provide transportation and storage service pursuant to Section 311 of the NGPA and Part 284 of the FERC's regulations. Under Section 311 of the NGPA, an intrastate pipeline company may transport gas for an interstate pipeline or any local distribution company served by an interstate pipeline without becoming subject to the FERC's jurisdiction under the NGA. However, such a pipeline is required to provide these services on an open and nondiscriminatory basis, and to make certain rate and other filings and reports are in compliance with the FERC's regulations. The rates for 311 services may be established by the FERC or the respective state agency, but such rates may not exceed a fair and equitable rate.

In September 2007, the FERC also approved an uncontested settlement establishing our maximum firm and interruptible transportation rates for NGPA Section 311 service on the Enterprise Texas Pipeline. In September 2008, we submitted to the FERC a new proposed Section 311 rate for service on our Sherman Extension pipeline, which rate is presently under review by the FERC. We are required to file another rate petition on or before April 2009 to justify our current rates or establish new rates for NGPA Section 311 service. The Texas Railroad Commission has the authority to regulate the rates and terms of service for our intrastate transportation service in Texas.

In September 2007, the FERC approved an uncontested settlement establishing our maximum firm and interruptible transportation rates for NGPA Section 311 service on the Enterprise Alabama Intrastate Pipeline. We are required to file another rate petition on or before May 2010 to justify our current rates or establish new rates for NGPA Section 311 service. The Alabama Public Service Commission has the authority to regulate the rates and terms of service for our intrastate transportation service in Alabama.

Sales of Natural Gas

We are engaged in natural gas marketing activities. The resale of natural gas in interstate commerce is subject to FERC jurisdiction. However, under current federal rules the price at which we sell natural gas currently is not regulated, insofar as the interstate market is concerned and, for the most part, is not subject to state regulation. Our affiliates that engage in natural gas marketing are considered marketing affiliates of our interstate natural gas pipelines. The FERC's rules require interstate pipelines and their marketing affiliates who sell natural gas in interstate commerce subject to the FERC's jurisdiction to adhere to standards of conduct that, among other things, require that their transmission and marketing employees function independently of each other. Pursuant to the Energy Policy Act of 2005, the FERC has established rules prohibiting energy market manipulation. A violation of these rules may subject us to civil penalties, disgorgement of unjust profits, suspension, loss of authorization to perform such sales or other appropriate non-monetary remedies imposed by the FERC.

The FERC is continually proposing and implementing new rules and regulations affecting segments of the natural gas industry. For example, the FERC recently established rules requiring certain non-interstate pipelines to post daily scheduled volume information and design capacity for certain points, and has also required the annual reporting of gas sales information, in order to increase transparency in natural gas markets. In November 2008, the FERC commenced an inquiry into whether to expand the contract reporting requirements of Section 311 service providers. We cannot predict the ultimate impact of these regulatory changes on our natural gas marketing activities; however, we believe that any new regulations will also be applied to other natural gas marketers with whom we compete.

Environmental and Safety Matters

General

Our operations are subject to multiple environmental obligations and potential liabilities under a variety of federal, state and local laws and regulations. These include, without limitation: the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Clean Air Act; the Federal Water Pollution Control Act or the Clean Water Act; the Oil Pollution Act; and analogous state and local laws and regulations. Such laws and regulations affect many aspects of our present and future operations, and generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals, with respect to air emissions, water quality, wastewater discharges and solid and hazardous waste management. Failure to comply with these requirements may expose us to fines, penalties and/or interruptions in our operations that could influence our financial position, results of operations and cash flows. If an accidental leak, spill or release of hazardous substances occurs at a facility that we own, operate or otherwise use, or where we send materials for treatment or disposal, we could be held jointly and severally liable for all resulting liabilities, including investigation, remedial and clean-up costs. Likewise, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination. Any or all of this could materially affect our financial position, results of operations and cash flows.

We believe our operations are in material compliance with applicable environmental and safety laws and regulations, other than certain matters discussed under Item 3 of this annual report, and that compliance with existing environmental and safety laws and regulations are not expected to have a material adverse effect on our financial position, results of operations and cash flows. Environmental and safety laws and regulations are subject to change. The clear trend in environmental regulation is to place more restrictions and limitations on activities that may be perceived to affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental regulation compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and cash flows.

Water

The Federal Water Pollution Control Act of 1972, as renamed and amended as the Clean Water Act ("CWA"), and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters of the United States, as well as state waters. Permits must be obtained to discharge pollutants into these waters. The CWA imposes substantial civil and criminal penalties for non-compliance. The Environmental Protection Agency ("EPA") has promulgated regulations that require us to have permits in order to discharge storm water runoff. The EPA has entered into agreements with states in which we operate whereby the permits are administered by the respective states.

The primary federal law for oil spill liability is the Oil Pollution Act of 1990 ("OPA"), which addresses three principal areas of oil pollution - prevention, containment and cleanup, and liability. The OPA subjects owners of certain facilities to strict, joint and potentially unlimited liability for containment and removal costs, natural resource damages and certain other consequences of an oil spill, where such spill affects navigable waters, along shorelines or in the exclusive economic zone of the United States. Any unpermitted release of petroleum or other pollutants from our operations could also result in fines or penalties. The OPA applies to vessels, offshore platforms and onshore facilities, including terminals, pipelines and transfer facilities. In order to handle, store or transport oil, shore facilities are required to file oil spill response plans with the United States Coast Guard, the United States Department of Transportation Office of Pipeline Safety ("OPS") or the EPA, as appropriate.

Some states maintain groundwater protection programs that require permits for discharges or commercial operations that may impact groundwater conditions. Groundwater contamination resulting from spills or releases of petroleum products is an inherent risk within the midstream energy industry. To the extent that groundwater contamination requiring remediation exists along our pipeline systems as a result of past operations, we believe any such contamination could be controlled or remedied without having a material adverse effect on our financial position, results of operations and cash flows, but such costs are site specific and we cannot predict that the effect will not be material in the aggregate.

Air Emissions

Our operations are subject to the Federal Clean Air Act (the "Clean Air Act") and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our facilities, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions.

Our permits and related compliance obligations under the Clean Air Act, as well as recent or soon to be adopted changes to state implementation plans for controlling air emissions in regional, non-attainment areas, may require our operations to incur capital expenditures to add to or modify existing air emission control equipment and strategies. In addition, some of our facilities are included within the categories of hazardous air pollutant sources, which are subject to increasing regulation under the Clean Air Act and many state laws. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and enforcement actions. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe, however, that such requirements will not have a material adverse effect on our operations, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

Some recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to the warming of the Earth's atmosphere. In response to such studies, the U.S. Congress is considering legislation to reduce emissions of greenhouse gases. In addition, at least 17 states have declined to wait on Congress to develop and implement climate control legislation and have already taken legal measures to reduce emissions of greenhouse gases. Also, as a result of the U.S. Supreme Court's decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA must consider whether it is required to regulate greenhouse gas emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Supreme Court's position in the *Massachusetts* case that greenhouse gases fall under the federal Clean Air Act's definition of "air pollutant" may also result in future regulation of greenhouse gas emissions from stationary sources under various Clean Air Act programs, including those that may be used in our operations. It is not possible at this time to predict how legislation that may be enacted to address greenhouse gas emissions would impact our business. However, future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial position, demand for our operations, results of operations, and cash flows.

Solid Waste

In our normal operations, we generate hazardous and non-hazardous solid wastes, including hazardous substances, that are subject to the requirements of the federal Resource Conservation and Recovery Act ("RCRA") and comparable state laws, which impose detailed requirements for the handling, storage treatment and disposal of hazardous and solid waste. We also utilize waste minimization and recycling processes to reduce the volumes of our waste. Amendments to RCRA required the EPA to promulgate regulations banning the land disposal of all hazardous wastes unless the waste meets certain treatment standards or the land-disposal method meets certain waste containment criteria. In the past, although we utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons and other materials may have been disposed of or released. In the future we may be required to remove or remediate these materials.

Environmental Remediation

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as "Superfund," imposes liability, without regard to fault or the legality of the original act, on certain classes of persons who contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of a facility where a release occurred, transporters that select the site of disposal of hazardous substances and companies that disposed of or arranged for the disposal of any hazardous substances found at a facility. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to take actions in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Despite the "petroleum exclusion" of CERCLA that currently encompasses natural gas, we may nonetheless handle "hazardous substances" subject to CERCLA in the course of our operations and our pipeline systems may generate wastes that fall within CERCLA's definition of a "hazardous substance." In the event a disposal facility previously used by us requires clean up in the future, we may be responsible under CERCLA for all or part of the costs required to clean up sites at which such wastes have been disposed.

Pipeline Safety Matters

We are subject to regulation by the United States Department of Transportation ("DOT") under the Accountable Pipeline and Safety Partnership Act of 1996, sometimes referred to as the Hazardous Liquid Pipeline Safety Act ("HLPSA"), and comparable state statutes relating to the design, installation, testing, construction, operation, replacement and management of our pipeline facilities. The HLPSA covers petroleum and petroleum products. The HLPSA requires any entity that owns or operates pipeline facilities to (i) comply with such regulations, (ii) permit access to and copying of records, (iii) file certain reports and (iv) provide information as required by the Secretary of Transportation. We believe that we are in material compliance with these HLPSA regulations.

We are also subject to the DOT regulation requiring qualification of pipeline personnel. The regulation requires pipeline operators to develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities. The intent of this regulation is to ensure a qualified work force and to reduce the probability and consequence of incidents caused by human error.

The regulation establishes qualification requirements for individuals performing covered tasks. We believe that we are in material compliance with these DOT regulations.

In addition, we are subject to the DOT Integrity Management regulations, which specify how companies should assess, evaluate, validate and maintain the integrity of pipeline segments that, in the event of a release, could impact High Consequence Areas ("HCAs"). HCAs are defined to include populated areas, unusually sensitive environmental areas and commercially navigable waterways. The regulation requires the development and implementation of an Integrity Management Program that utilizes internal pipeline inspection, pressure testing, or other equally effective means to assess the integrity of HCA pipeline segments. The regulation also requires periodic review of HCA pipeline segments to ensure that adequate preventative and mitigative measures exist and that companies take prompt action to address integrity issues raised by the assessment and analysis. We have identified our HCA pipeline segments and developed an appropriate Integrity Management Program.

Risk Management Plans

We are subject to the EPA's Risk Management Plan regulations at certain facilities. These regulations are intended to work with the Occupational Safety and Health Act ("OSHA") Process Safety Management regulations (see "Safety Matters" below) to minimize the offsite consequences of catastrophic releases. The regulations required us to develop and implement a risk management program that includes a five-year accident history, an offsite consequence analysis process, a prevention program and an emergency response program. We believe we are operating in material compliance with our risk management program.

Safety Matters

Certain of our facilities are also subject to the requirements of the federal OSHA and comparable state statutes. We believe we are in material compliance with OSHA and state requirements, including general industry standards, record keeping requirements and monitoring of occupational exposures.

We are subject to OSHA Process Safety Management ("PSM") regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves certain flammable liquid or gas. We believe we are in material compliance with the OSHA PSM regulations.

The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require us to organize and disclose information about the hazardous materials used in our operations. Certain parts of this information must be reported to employees, state and local governmental authorities and local citizens upon request.

Employees

Like many publicly traded partnerships, we have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement (the "ASA"). For additional information regarding the ASA, see "EPCO Administrative Services Agreement" under Item 13 of this annual report. As of December 31, 2008, there were approximately 3,500 EPCO personnel who spend all or a portion of their time engaged in our business. Approximately 2,100 of these individuals devote all of their time performing management and operating duties for us. The remaining approximate 1,400 personnel are part of EPCO's shared service organization and spend a portion of their time engaged in our business.

Available Information

As a large accelerated filer, we electronically file certain documents with the U.S. Securities and Exchange Commission ("SEC"). We file annual reports on Form 10-K; quarterly reports on Form 10-Q; and current reports on Form 8-K (as appropriate); along with any related amendments and supplements thereto. Occasionally, we may also file registration statements and related documents in connection with equity or debt offerings. You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain information regarding the Public Reference Room by calling the SEC at (800) SEC-0330. In addition, the SEC maintains an Internet website at www.sec.gov that contains reports and other information regarding registrants that file electronically with the SEC, including us.

We provide electronic access to our periodic and current reports on our Internet website, www.epplp.com. These reports are available as soon as reasonably practicable after we electronically file such materials with, or furnish such materials to, the SEC. You may also contact our investor relations department at (866) 230-0745 for paper copies of these reports free of charge.

Item 1A. *Risk Factors*.

An investment in our common units involves certain risks. If any of these risks were to occur, our business, financial position, results of operations and cash flows could be materially adversely affected. In that case, the trading price of our common units could decline and you could lose part or all of your investment.

The following section lists some, but not all, of the key risk factors that may have a direct impact on our business, financial position, results of operations and cash flows.

Risks Relating to Our Business

Changes in demand for and production of hydrocarbon products may materially adversely affect our financial position, results of operations and cash flows.

We operate predominantly in the midstream energy sector which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs and crude oil. As such, our financial position, results of operations and cash flows may be materially adversely affected by changes in the prices of these hydrocarbon products and by changes in the relative price levels among these hydrocarbon products. Changes in prices and relative price levels may impact demand for hydrocarbon products, which in turn may impact production, demand and volumes of product for which we provide services. We may also incur credit and price risk to the extent counterparties do not perform in connection with our marketing of natural gas, NGLs and propylene.

In the past, the price of natural gas has been extremely volatile, and we expect this volatility to continue. The New York Mercantile Exchange daily settlement price for natural gas for the prompt month contract in 2006 ranged from a high of $10.63 per MMBtu to a low of $4.20 per MMBtu. In 2007, the same index ranged from a high of $8.64 per MMBtu to a low of $5.38 per MMBtu. In 2008, the same index ranged from a high of $13.58 per MMBtu to a low of $5.29 per MMBtu.

Generally, the prices of natural gas, NGLs, crude oil and other hydrocarbon products are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors that are impossible to control. Some of these factors include:

- the level of domestic production and consumer product demand;
- the availability of imported oil and natural gas;

- actions taken by foreign oil and natural gas producing nations;
- the availability of transportation systems with adequate capacity;
- the availability of competitive fuels;
- fluctuating and seasonal demand for oil, natural gas and NGLs;
- the impact of conservation efforts;
- the extent of governmental regulation and taxation of production; and
- the overall economic environment.

We are exposed to natural gas and NGL commodity price risk under certain of our natural gas processing and gathering and NGL fractionation contracts that provide for our fees to be calculated based on a regional natural gas or NGL price index or to be paid in-kind by taking title to natural gas or NGLs. A decrease in natural gas and NGL prices can result in lower margins from these contracts, which may materially adversely affect our financial position, results of operations and cash flows.

Our operating results in one or more geographic regions may also be affected by uncertain or changing economic conditions within that region, such as the challenges that are currently affecting economic conditions in the United States. Volatility in commodity prices may also have an impact on many of our customers, which in turn could have a negative impact on their ability to meet their obligations to us.

A decline in the volume of natural gas, NGLs and crude oil delivered to our facilities could adversely affect our financial position, results of operations and cash flows.

Our profitability could be materially impacted by a decline in the volume of natural gas, NGLs and crude oil transported, gathered or processed at our facilities. A material decrease in natural gas or crude oil production or crude oil refining, as a result of depressed commodity prices, a decrease in domestic and international exploration and development activities or otherwise, could result in a decline in the volume of natural gas, NGLs and crude oil handled by our facilities.

The crude oil, natural gas and NGLs currently transported, gathered or processed at our facilities originate from existing domestic and international resource basins, which naturally deplete over time. To offset this natural decline, our facilities will need access to production from newly discovered properties that are either being developed or expected to be developed. Exploration and development of new oil and natural gas reserves is capital intensive, particularly offshore in the Gulf of Mexico. Many economic and business factors are beyond our control and can adversely affect the decision by producers to explore for and develop new reserves. These factors could include relatively low oil and natural gas prices, cost and availability of equipment and labor, regulatory changes, capital budget limitations, the lack of available capital or the probability of success in finding hydrocarbons. For example, a sustained decline in the price of natural gas and crude oil could result in a decrease in natural gas and crude oil exploration and development activities in the regions where our facilities are located. This could result in a decrease in volumes to our offshore platforms, natural gas processing plants, natural gas, crude oil and NGL pipelines, and NGL fractionators, which would have a material adverse affect on our financial position, results of operations and cash flows. Additional reserves, if discovered, may not be developed in the near future or at all.

In addition, imported liquefied natural gas ("LNG"), is expected to be a significant component of future natural gas supply to the United States. Much of this increase in LNG supplies is expected to be imported through new LNG facilities to be developed over the next decade. Twelve LNG projects have been approved by the FERC to be constructed in the Gulf Coast region and an additional two LNG projects have been proposed for the region. We cannot predict which, if any, of these new projects will be constructed. We may not realize expected increases in future natural gas supply available to our facilities and pipelines if (i) a significant number of these new projects fail to be developed with their announced capacity, (ii) there are significant delays in such development, (iii) they are built in locations where they are not connected to our assets or (iv) they do not influence sources of supply on our systems. If the expected increase in natural gas supply through imported LNG is not realized, projected natural gas throughput on our pipelines would decline, which could have a material adverse effect on our financial position, results of operations and cash flows.

A decrease in demand for NGL products by the petrochemical, refining or heating industries could materially adversely affect our financial position, results of operations and cash flows.

A decrease in demand for NGL products by the petrochemical, refining or heating industries, whether because of general economic conditions, reduced demand by consumers for the end products made with NGL products, increased competition from petroleum-based products due to pricing differences, adverse weather conditions, government regulations affecting prices and production levels of natural gas or the content of motor gasoline or other reasons, could materially adversely affect our financial position, results of operations and cash flows. For example:

Ethane. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. If natural gas prices increase significantly in relation to NGL product prices or if the demand for ethylene falls (and, therefore, the demand for ethane by NGL producers falls), it may be more profitable for natural gas producers to leave the ethane in the natural gas stream to be burned as fuel than to extract the ethane from the mixed NGL stream for sale as an ethylene feedstock.

Propane. The demand for propane as a heating fuel is significantly affected by weather conditions. Unusually warm winters could cause the demand for propane to decline significantly and could cause a significant decline in the volumes of propane that we transport.

Isobutane. A reduction in demand for motor gasoline additives may reduce demand for isobutane. During periods in which the difference in market prices between isobutane and normal butane is low or inventory values are high relative to current prices for normal butane or isobutane, our operating margin from selling isobutane could be reduced.

Propylene. Propylene is sold to petrochemical companies for a variety of uses, principally for the production of polypropylene. Propylene is subject to rapid and material price fluctuations. Any downturn in the domestic or international economy could cause reduced demand for, and an oversupply of propylene, which could cause a reduction in the volumes of propylene that we transport.

We face competition from third parties in our midstream businesses

Even if crude oil and natural gas reserves exist in the areas accessed by our facilities and are ultimately produced, we may not be chosen by the producers in these areas to gather, transport, process, fractionate, store or otherwise handle the hydrocarbons that are produced. We compete with others, including producers of oil and natural gas, for any such production on the basis of many factors, including but not limited to:

- geographic proximity to the production;
- costs of connection;
- available capacity;
- rates; and
- access to markets.

Our future debt level may limit our flexibility to obtain additional financing and pursue other business opportunities.

As of December 31, 2008, we had approximately $9.05 billion of consolidated debt outstanding including Duncan Energy Partners, which had approximately $484.3 million of consolidated debt outstanding. The amount of our future debt could have significant effects on our operations, including, among other things:

- a substantial portion of our cash flow, including that of Duncan Energy Partners, could be dedicated to the payment of principal and interest on our future debt and may not be available for other purposes, including the payment of distributions on our common units and capital expenditures;

- credit rating agencies may view our debt level negatively;

- covenants contained in our existing and future credit and debt arrangements will require us to continue to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;

- we may be at a competitive disadvantage relative to similar companies that have less debt; and

- we may be more vulnerable to adverse economic and industry conditions as a result of our significant debt level.

Our public debt indentures currently do not limit the amount of future indebtedness that we can create, incur, assume or guarantee. Although EPO's Multi-Year Revolving Credit Facility restricts our ability to incur additional debt above certain levels, any debt we may incur in compliance with these restrictions may still be substantial. For information regarding EPO's Multi-Year Revolving Credit Facility, see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

EPO's Multi-Year Revolving Credit Facility, its Japanese Yen Term Loan and each of its indentures for public debt contain conventional financial covenants and other restrictions. For example, we are prohibited from making distributions to our partners if such distributions would cause an event of default or otherwise violate a covenant under EPO's Multi-Year Revolving Credit Facility. In addition, under the terms of our junior subordinated notes, generally, if we elect to defer interest payments thereon, we are restricted from making distributions with respect to our equity securities. A breach of any of these restrictions by us could permit our lenders or noteholders, as applicable, to declare all amounts outstanding under these debt agreements to be immediately due and payable and, in the case of EPO's Multi-Year Revolving Credit Facility, to terminate all commitments to extend further credit.

Our ability to access capital markets to raise capital on favorable terms could be affected by our debt level, the amount of our debt maturing in the next several years and current maturities, and by prevailing market conditions. Moreover, if the rating agencies were to downgrade our credit ratings, then we could experience an increase in our borrowing costs, difficulty assessing capital markets or a reduction in the market price of our common units. Such a development could adversely affect our ability to obtain financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness. If we are unable to access the capital markets on favorable terms in the future, we might be forced to seek extensions for some of our short-term securities or to refinance some of our debt obligations through bank credit, as opposed to long-term public debt securities or equity securities. The price and terms upon which we might receive such extensions or additional bank credit, if at all, could be more onerous than those contained in existing debt agreements. Any such arrangements could, in turn, increase the risk that our leverage may adversely affect our future financial and operating flexibility and thereby impact our ability to pay cash distributions at expected levels.

We may not be able to fully execute our growth strategy if we encounter illiquid capital markets or increased competition for investment opportunities.

Our strategy contemplates growth through the development and acquisition of a wide range of midstream and other energy infrastructure assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses to enhance our ability to compete effectively and diversifying our asset portfolio, thereby providing more stable cash flow. We regularly consider and enter into discussions regarding, and are currently contemplating and/or pursuing, potential joint ventures, stand alone projects or other transactions that we believe will present opportunities to realize synergies, expand our role in the energy infrastructure business and increase our market position.

We will require substantial new capital to finance the future development and acquisition of assets and businesses. Any limitations on our access to capital will impair our ability to execute this strategy. If the cost of such capital becomes too expensive, our ability to develop or acquire accretive assets will be limited. We may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors that influence our initial cost of equity include market conditions, fees we pay to underwriters and other offering costs, which include amounts we pay for legal and accounting services. The primary factors influencing our cost of borrowing include interest rates, credit spreads, covenants, underwriting or loan origination fees and similar charges we pay to lenders.

Recent conditions in the financial markets have limited our ability to access equity and credit markets. Generally, credit has become more expensive and difficult to obtain, and the cost of equity capital has also become more expensive. Some lenders are imposing more stringent credit terms and there may be a general reduction in the amount of credit available in the markets in which we conduct business. Tightening of the credit markets may have a material adverse effect on us by, among other things, decreasing our ability to finance expansion projects or business acquisitions on favorable terms and by the imposition of increasingly restrictive borrowing covenants. In addition, the distribution yields of new equity issued may be at a higher yield than our historical levels, making additional equity issuances more expensive.

We also compete for the types of assets and businesses we have historically purchased or acquired. Increased competition for a limited pool of assets could result in our losing to other bidders more often or acquiring assets at less attractive prices. Either occurrence would limit our ability to fully execute our growth strategy. Our inability to execute our growth strategy may materially adversely affect our ability to maintain or pay higher distributions in the future.

Our variable rate debt and future maturities of fixed-rate, long-term debt make us vulnerable to increases in interest rates. Increases in interest rates could materially adversely affect our business, financial position, results of operation and cash flows.

As of December 31, 2008, we had outstanding $9.05 billion of consolidated debt (excluding the value of interest rate swaps and currency swaps). Of this amount, approximately $1.57 billion, or 17.3%, was subject to variable interest rates, either as short-term or long-term variable rate debt obligations or as long-term fixed-rate debt converted to variable rates through the use of interest rate swaps. We have approximately $217.6 million in 4.93% fixed-rate debt maturing in March 2009. We also have an additional $500.0 million of 4.625% fixed-rate Senior Notes maturing in October 2009, $54.0 million of 8.70% fixed-rate debt maturing in March 2010, and $500.0 million of 4.95% fixed-rate Senior Notes maturing in June 2010. The rate on our December 2008 issuance of $500.0 million of Senior Notes due January 2014 was 9.75%. Should interest rates continue at current levels or increase significantly, the amount of cash required to service our debt would increase. As a result, our financial position, results of operations and cash flows, could be materially adversely affected.

An increase in interest rates may also cause a corresponding decline in demand for equity investments, in general, and in particular, for yield-based equity investments such as our common units. Any such reduction in demand for our common units resulting from other more attractive investment opportunities may cause the trading price of our common units to decline.

Operating cash flows from our capital projects may not be immediate.

We have announced and are engaged in several construction projects involving existing and new facilities for which we have expended or will expend significant capital, and our operating cash flow from a particular project may not increase until a period of time after its completion. For instance, if we build a new pipeline or platform or expand an existing facility, the design, construction, development and installation may occur over an extended period of time, and we may not receive any material increase in operating cash flow from that project until a period of time after it is placed in-service. If we experience any unanticipated or extended delays in generating operating cash flow from these projects, we may be required to reduce or reprioritize our capital budget, sell non-core assets, access the capital markets or decrease or limit distributions to unitholders in order to meet our capital requirements.

Our growth strategy may adversely affect our results of operations if we do not successfully integrate the businesses that we acquire or if we substantially increase our indebtedness and contingent liabilities to make acquisitions.

Our growth strategy includes making accretive acquisitions. As a result, from time to time, we will evaluate and acquire assets and businesses (either ourselves or Duncan Energy Partners may do so) that we believe complement our existing operations. We may be unable to integrate successfully businesses we acquire in the future. We may incur substantial expenses or encounter delays or other problems in connection with our growth strategy that could negatively impact our financial position, results of operations and cash flows.

Moreover, acquisitions and business expansions involve numerous risks, including but not limited to:

- difficulties in the assimilation of the operations, technologies, services and products of the acquired companies or business segments;
- establishing the internal controls and procedures that we are required to maintain under the Sarbanes-Oxley Act of 2002;
- managing relationships with new joint venture partners with whom we have not previously partnered;
- inefficiencies and complexities that can arise because of unfamiliarity with new assets and the businesses associated with them, including with their markets; and
- diversion of the attention of management and other personnel from day-to-day business to the development or acquisition of new businesses and other business opportunities.

If consummated, any acquisition or investment would also likely result in the incurrence of indebtedness and contingent liabilities and an increase in interest expense and depreciation, accretion and amortization expenses. As a result, our capitalization and results of operations may change significantly following an acquisition. A substantial increase in our indebtedness and contingent liabilities could have a material adverse effect on our financial position, results of operations and cash flows. In addition, any anticipated benefits of a material acquisition, such as expected cost savings, may not be fully realized, if at all.

Acquisitions that appear to be accretive may nevertheless reduce our cash from operations on a per unit basis.

Even if we make acquisitions that we believe will be accretive, these acquisitions may nevertheless reduce our cash from operations on a per unit basis. Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about volumes, revenues and costs, including synergies;
- an inability to integrate successfully the businesses we acquire;
- decrease in our liquidity as a result of our using a significant portion of our available cash or borrowing capacity to finance the acquisition;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance the acquisition;
- the assumption of unknown liabilities for which we are not indemnified or for which our indemnity is inadequate;
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business concerns;
- unforeseen difficulties operating in new product areas or new geographic areas; and
- customer or key employee losses at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

Our actual construction, development and acquisition costs could exceed forecasted amounts.

We have significant expenditures for the development and construction of midstream energy infrastructure assets, including construction and development projects with significant logistical, technological and staffing challenges. We may not be able to complete our projects at the costs we estimated at the time of each project's initiation or that we currently estimate. For example, material and labor costs associated with our projects in the Rocky Mountains region increased over time due to factors such as higher transportation costs and the availability of construction personnel. Similarly, force majeure events such as hurricanes along the Gulf Coast may cause delays, shortages of skilled labor and additional expenses for these construction and development projects, as were experienced with Hurricanes Gustav and Ike in 2008.

Our construction of new assets is subject to regulatory, environmental, political, legal and economic risks, which may result in delays, increased costs or decreased cash flows.

One of the ways we intend to grow our business is through the construction of new midstream energy assets. The construction of new assets involves numerous operational, regulatory, environmental, political and legal risks beyond our control and may require the expenditure of significant amounts of capital. These potential risks include, among other things, the following:

- we may be unable to complete construction projects on schedule or at the budgeted cost due to the unavailability of required construction personnel or materials, accidents, weather conditions or an inability to obtain necessary permits;

- we will not receive any material increases in revenues until the project is completed, even though we may have expended considerable funds during the construction phase, which may be prolonged;

- we may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize;

- since we are not engaged in the exploration for and development of natural gas reserves, we may not have access to third-party estimates of reserves in an area prior to our constructing facilities in the area. As a result, we may construct facilities in an area where the reserves are materially lower than we anticipate;

- where we do rely on third-party estimates of reserves in making a decision to construct facilities, these estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating reserves; and

- we may be unable to obtain rights-of-way to construct additional pipelines or the cost to do so may be uneconomical.

A materialization of any of these risks could adversely affect our ability to achieve growth in the level of our cash flows or realize benefits from expansion opportunities or construction projects.

Substantially all of the common units in us that are owned by EPCO and its affiliates are pledged as security under EPCO's credit facility. Additionally, all of the member interests in our general partner and all of the common units in us that are owned by Enterprise GP Holdings are pledged under its credit facility. Upon an event of default under either of these credit facilities, a change in ownership or control of us could ultimately result.

An affiliate of EPCO has pledged substantially all of its common units in us as security under its credit facility. EPCO's credit facility contains customary and other events of default relating to defaults of EPCO and certain of its subsidiaries, including certain defaults by us and other affiliates of EPCO. An event of default, followed by a foreclosure on EPCO's pledged collateral, could ultimately result in a change in ownership of us. In addition, the 100.0% membership interest in our general partner and the 13,670,925 of our common units that are owned by Enterprise GP Holdings are pledged under Enterprise GP Holdings' credit facility. Enterprise GP Holdings' credit facility contains customary and other events of default. Upon an event of default, the lenders under Enterprise GP Holdings' credit facility could foreclose on Enterprise GP Holdings' assets, which could ultimately result in a change in control of our general partner and a change in the ownership of our units held by Enterprise GP Holdings.

The credit and risk profile of our general partner and its owners could adversely affect our credit ratings and profile.

The credit and business risk profiles of the general partner or owners of a general partner may be factors in credit evaluations of a master limited partnership. This is because the general partner can exercise significant influence over the business activities of the partnership, including its cash distribution and acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of the general partner and its owners, including the degree of their financial leverage and their dependence on cash flow from the partnership to service their indebtedness.

Entities controlling the owner of our general partner have significant indebtedness outstanding and are dependent principally on the cash distributions from their limited partner equity interests in us, Enterprise GP Holdings and TEPPCO to service such indebtedness. Any distributions by us, Enterprise GP Holdings and TEPPCO to such entities will be made only after satisfying our then current obligations to creditors. Although we have taken certain steps in our organizational structure, financial reporting and contractual relationships to reflect the separateness of us and our general partner from the entities that control our general partner, our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of EPCO or the entities that control our general partner were viewed as substantially lower or more risky than ours.

The interruption of distributions to us from our subsidiaries and joint ventures may affect our ability to satisfy our obligations and to make distributions to our partners.

We are a holding company with no business operations and our operating subsidiaries conduct all of our operations and own all of our operating assets. Our only significant assets are the ownership interests we own in our subsidiaries and joint ventures. As a result, we depend upon the earnings and cash flow of our subsidiaries and joint ventures and the distribution of that cash to us in order to meet our obligations and to allow us to make distributions to our partners. The ability of our subsidiaries and joint ventures to make distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable state partnership and limited liability company laws and other laws and regulations, including FERC policies. For example, all cash flows from Evangeline are currently used to service its debt.

As of December 31, 2008, we also owned 5,393,100 common units and 37,333,887 Class B units of Duncan Energy Partners (these Class B units automatically converted to common units of Duncan Energy Partners on February 1, 2009), representing approximately 74.1% of its outstanding limited partner units, and owned minority equity interests in subsidiaries of Duncan Energy Partners that held total assets of approximately $4.6 billion as of December 31, 2008. With respect to three subsidiaries of Duncan Energy Partners acquired from us on December 8, 2008 that held approximately $3.5 billion of total assets as of December 31, 2008, Duncan Energy Partners has effective priority rights to specified quarterly distribution amounts ahead of distributions on our retained equity interests in these subsidiaries.

In addition, the charter documents governing our joint ventures typically allow their respective joint venture management committees sole discretion regarding the occurrence and amount of distributions. Some of the joint ventures in which we participate have separate credit agreements that contain various restrictive covenants. Among other things, those covenants may limit or restrict the joint venture's ability to make distributions to us under certain circumstances. Accordingly, our joint ventures may be unable to make distributions to us at current levels if at all.

We may be unable to cause our joint ventures to take or not to take certain actions unless some or all of our joint venture participants agree.

We participate in several joint ventures. Due to the nature of some of these arrangements, each participant in these joint ventures has made substantial investments in the joint venture and, accordingly, has required that the relevant charter documents contain certain features designed to provide each participant with the opportunity to participate in the management of the joint venture and to protect its investment, as well as any other assets which may be substantially dependent on or otherwise affected by the activities of that joint venture. These participation and protective features customarily include a corporate governance structure that requires at least a majority-in-interest vote to authorize many basic activities and requires a greater voting interest (sometimes up to 100.0%) to authorize more significant activities. Examples of these more significant activities are large expenditures or contractual commitments, the construction or acquisition of assets, borrowing money or otherwise raising capital, transactions with affiliates of a joint venture participant, litigation and transactions not in the ordinary course of business, among others. Thus, without the concurrence of joint venture participants with enough voting interests, we may be unable to cause any of our joint ventures to take or not to take certain actions, even though those actions may be in the best interest of us or the particular joint venture.

Moreover, any joint venture owner may sell, transfer or otherwise modify its ownership interest in a joint venture, whether in a transaction involving third parties or the other joint venture owners. Any such transaction could result in us being required to partner with different or additional parties.

A natural disaster, catastrophe or other event could result in severe personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow and, accordingly, affect the market price of our common units.

Some of our operations involve risks of personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow. For example, natural gas facilities operate at high pressures, sometimes in excess of 1,100 pounds per square inch. We also operate oil and natural gas facilities located underwater in the Gulf of Mexico, which can involve complexities, such as extreme water pressure. Virtually all of our operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and/or earthquakes. The location of our assets and our customers' assets in the U.S. Gulf Coast region makes them particularly vulnerable to hurricane risk.

If one or more facilities that are owned by us or that deliver oil, natural gas or other products to us are damaged by severe weather or any other disaster, accident, catastrophe or event, our operations could be significantly interrupted. Similar interruptions could result from damage to production or other facilities that supply our facilities or other stoppages arising from factors beyond our control. These interruptions might involve significant damage to people, property or the environment, and repairs might take from a week or less for a minor incident to six months or more for a major interruption. Additionally, some of the storage contracts that we are a party to obligate us to indemnify our customers for any damage or injury occurring during the period in which the customers' natural gas is in our possession. Any event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions and, accordingly, adversely affect the market price of our common units.

We believe that EPCO maintains adequate insurance coverage on our behalf, although insurance will not cover many types of interruptions that might occur and will not cover amounts up to applicable deductibles. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. For example, change in the insurance markets subsequent to the hurricanes in 2005 and 2008 have made it more difficult for us to obtain certain types of coverage. As a result, EPCO may not be able to renew existing insurance policies on behalf of us or procure other desirable insurance on commercially reasonable terms, if at all. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position, results of operations and cash flows. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

An impairment of goodwill and intangible assets could reduce our earnings.

At December 31, 2008, our balance sheet reflected $706.9 million of goodwill and $855.4 million of intangible assets. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. Generally accepted accounting principles in the United States ("GAAP") require us to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Long-lived assets such as intangible assets with finite useful lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If we determine that any of our goodwill or intangible assets were impaired, we would be required to take an immediate charge to earnings with a correlative effect on partners' equity and balance sheet leverage as measured by debt to total capitalization.

The use of derivative financial instruments could result in material financial losses by us.

We historically have sought to limit a portion of the adverse effects resulting from changes in energy commodity prices and interest rates by using financial derivative instruments and other hedging mechanisms from time to time. To the extent that we hedge our commodity price and interest rate exposures, we will forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor. In addition, even though monitored by management, hedging activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the hedge arrangement, the hedge is imperfect, or hedging policies and procedures are not followed.

Our pipeline integrity program may impose significant costs and liabilities on us.

The U.S. DOT issued final rules (effective March 2001 with respect to hazardous liquid pipelines and February 2004 with respect to natural gas pipelines) requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rules refer to as “high consequence areas.” The final rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002. At this time, we cannot predict the ultimate costs of compliance with this rule because those costs will depend on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing that is required by the rule. We will continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

Environmental costs and liabilities and changing environmental regulation, including climate change regulation, could affect our results of operations, cash flows and financial condition.

Our operations are subject to extensive federal, state and local regulatory requirements relating to environmental affairs, health and safety, waste management and chemical and petroleum products. Further, we cannot ensure that existing environmental regulations will not be revised or that new regulations, such as regulations designed to reduce the emissions of greenhouse gases, will not be adopted or become applicable to us. Governmental authorities have the power to enforce compliance with applicable regulations and permits and to subject violators to civil and criminal penalties, including substantial fines, injunctions or both. Certain environmental laws, including CERCLA and analogous state laws and regulations, impose strict, joint and several liability for costs required to cleanup and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, third parties, including neighboring landowners, may also have the right to pursue legal actions to enforce compliance or to recover for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

We will make expenditures in connection with environmental matters as part of normal capital expenditure programs. However, future environmental law developments, such as stricter laws, regulations, permits or enforcement policies, could significantly increase some costs of our operations, including the handling, manufacture, use, emission or disposal of substances and wastes.

Climate change regulation is one area of potential future environmental law development. Studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases,” may be contributing to warming of the Earth’s atmosphere. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas, are examples of greenhouse gases. The U.S. Congress is considering legislation to reduce emissions of greenhouse gases. In addition, at least nine states in the Northeast and five states in the West have developed initiatives to regulate emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. The EPA is separately considering whether it will regulate greenhouse gases as “air pollutants” under the existing federal Clean Air Act.

Passage of climate control legislation or other regulatory initiatives by Congress or various states of the U.S. or the adoption of regulations by the EPA or analogous state agencies that regulate or restrict emissions of greenhouse gases, including methane or carbon dioxide in areas in which we conduct business, could result in changes to the consumption and demand for natural gas and could have adverse effects on our business, financial position, results of operations and prospects. These changes could increase the costs of our operations, including costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. While we may be able to include some or all of such increased costs in the rates charged by our pipelines or other facilities, such recovery of costs is uncertain and may depend on events beyond our control, including the outcome of future rate proceedings before the FERC and the provisions of any final legislation.

Federal, state or local regulatory measures could materially adversely affect our business, results of operations, cash flows and financial condition.

The FERC regulates our interstate natural gas pipelines and natural gas storage facilities under the Natural Gas Act, and interstate NGL and petrochemical pipelines under the ICA. The STB regulates our interstate propylene pipelines. State regulatory agencies regulate our intrastate natural gas and NGL pipelines, intrastate storage facilities and gathering lines.

Under the NGA, the FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Its authority to regulate those services is comprehensive and includes the rates charged for the services, terms and condition of service and certification and construction of new facilities. The FERC requires that our services are provided on a non-discriminatory basis so that all shippers have open access to our pipelines and storage. Pursuant to the FERC's jurisdiction over interstate gas pipeline rates, existing pipeline rates may be challenged by customer complaint or by the FERC Staff and proposed rate increases may be challenged by protest.

We have interests in natural gas pipeline facilities offshore from Texas and Louisiana. These facilities are subject to regulation by the FERC and other federal agencies, including the Department of Interior, under the Outer Continental Shelf Lands Act, and by the DOT's OPS under the Natural Gas Pipeline Safety Act.

Our intrastate NGL and natural gas pipelines are subject to regulation in many states, including Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas, and by the FERC pursuant to Section 311 of the Natural Gas Policy Act. We also have natural gas underground storage facilities in Louisiana, Mississippi and Texas. Although state regulation is typically less onerous than at the FERC, proposed and existing rates subject to state regulation and the provision of services on a non-discriminatory basis are also subject to challenge by protest and complaint, respectively.

For a general overview of federal, state and local regulation applicable to our assets, see "Regulation" included under Items 1 and 2 of this annual report. This regulatory oversight can affect certain aspects of our business and the market for our products and could materially adversely affect our cash flows.

We are subject to strict regulations at many of our facilities regarding employee safety, and failure to comply with these regulations could adversely affect our ability to make distributions to unitholders.

The workplaces associated with our facilities are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that we maintain information about hazardous materials used or produced in our operations and that we provide this information to employees, state and local governmental authorities and local residents. The failure to comply with OSHA requirements or general industry standards, keep adequate records or monitor occupational exposure to regulated substances could have a material adverse effect on our business, financial position, results of operations and ability to make distributions to unitholders.

Terrorist attacks aimed at our facilities could adversely affect our business, results of operations, cash flows and financial condition.

Since the September 11, 2001 terrorist attacks on the United States, the United States government has issued warnings that energy assets, including our nation's pipeline infrastructure, may be the future target of terrorist organizations. Any terrorist attack on our facilities or pipelines or those of our customers could have a material adverse effect on our business.

We depend on the leadership and involvement of Dan L. Duncan and other key personnel for the success of our businesses.

We depend on the leadership, involvement and services of Dan L. Duncan, the founder of EPCO and the chairman of our general partner and other key personnel. Mr. Duncan has been integral to our success and the success of EPCO due in part to his ability to identify and develop business opportunities, make strategic decisions and attract and retain key personnel. The loss of his leadership and involvement or the services of certain key members of our senior management team could have a material adverse effect on our business, financial position, results of operations, cash flows and market price of our securities.

EPCO's employees may be subjected to conflicts in managing our business and the allocation of time and compensation costs between our business and the business of EPCO and its other affiliates.

We have no officers or employees and rely solely on officers of our general partner and employees of EPCO. Certain of our officers are also officers of EPCO and other affiliates of EPCO. These relationships may create conflicts of interest regarding corporate opportunities and other matters, and the resolution of any such conflicts may not always be in our or our unitholders' best interests. In addition, these overlapping officers allocate their time among us, EPCO and other affiliates of EPCO. These officers face potential conflicts regarding the allocation of their time, which may adversely affect our business, results of operations and financial condition.

We have entered into an ASA that governs business opportunities among entities controlled by EPCO, which includes us and our general partner, Enterprise GP Holdings and its general partner, Duncan Energy Partners and its general partner and TEPPCO and its general partner. For information regarding how business opportunities are handled within the EPCO group of companies, please read Item 13 of this annual report.

We do not have an independent compensation committee, and aspects of the compensation of our executive officers and other key employees, including base salary, are not reviewed or approved by our independent directors. The determination of executive officer and key employee compensation could involve conflicts of interest resulting in economically unfavorable arrangements for us.

The global financial crisis may have impacts on our business and financial condition that we currently cannot predict.

The continued credit crisis and related turmoil in the global financial system has had, and may continue to have, an impact on our business and financial condition. We may face significant challenges if conditions in the financial markets revert to those that existed in the fourth quarter of 2008. Our ability to access the capital markets may be severely restricted at a time when we would like, or need, to do so, which could have an adverse impact on our ability to meet capital commitments and achieve the flexibility needed to react to changing economic and business conditions. The credit crisis could have a negative impact on our lenders or customers, causing them to fail to meet their obligations to us. Additionally, demand for our services and products depends on activity and expenditure levels in the energy industry, which are directly and negatively impacted by depressed oil and gas prices. Also, a decrease in demand for NGLs by the petrochemical and refining industries due to a decrease in demand for their products as a result of general economic conditions would likely impact demand for our services and products. Any of these factors could lead to reduced usage of our pipelines and energy logistics services, which could have a material negative impact on our revenues and prospects.

Risks Relating to Our Partnership Structure

We may issue additional securities without the approval of our common unitholders.

At any time, we may issue an unlimited number of limited partner interests of any type (to parties other than our affiliates) without the approval of our unitholders. Our partnership agreement does not give our common unitholders the right to approve the issuance of equity securities including equity securities ranking senior to our common units. The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

- the ownership interest of a unitholder immediately prior to the issuance will decrease;
- the amount of cash available for distributions on each common unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding common unit may be diminished; and
- the market price of our common units may decline.

We may not have sufficient cash from operations to pay distributions at the current level following establishment of cash reserves and payments of fees and expenses, including payments to EPGP.

Because distributions on our common units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance. We cannot guarantee that we will continue to pay distributions at the current level each quarter. The actual amount of cash that is available to be distributed each quarter will depend upon numerous factors, some of which are beyond our control and the control of EPGP. These factors include but are not limited to the following:

- the level of our operating costs;
- the level of competition in our business segments;
- prevailing economic conditions;
- the level of capital expenditures we make;
- the restrictions contained in our debt agreements and our debt service requirements;
- fluctuations in our working capital needs;
- the cost of acquisitions, if any; and
- the amount, if any, of cash reserves established by EPGP in its sole discretion.

In addition, you should be aware that the amount of cash we have available for distribution depends primarily on our cash flow, including cash flow from financial reserves and working capital borrowings, not solely on profitability, which is affected by non-cash items. As a result, we may make cash distributions during periods when we record losses and we may not make distributions during periods when we record net income.

We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.

Unlike a corporation, our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash reduced by any amounts of reserves for commitments and contingencies, including capital and operating costs and debt service requirements. The value of our units and other limited partner interests may decrease in correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue more equity to recapitalize.

Cost reimbursements and fees due to EPCO and its affiliates, including our general partner may be substantial and will reduce our cash available for distribution to holders of our units.

Prior to making any distribution on our units, we will reimburse EPCO and its affiliates, including officers and directors of EPGP, for all expenses they incur on our behalf, including allocated overhead. These amounts will include all costs incurred in managing and operating us, including costs for rendering administrative staff and support services to us, and overhead allocated to us by EPCO. The payment of these amounts could adversely affect our ability to pay cash distributions to holders of our units. EPCO has sole discretion to determine the amount of these expenses. In addition, EPCO and its affiliates may provide other services to us for which we will be charged fees as determined by EPCO.

EPGP and its affiliates have limited fiduciary responsibilities to, and conflicts of interest with respect to, our partnership, which may permit it to favor its own interests to your detriment.

The directors and officers of EPGP and its affiliates have duties to manage EPGP in a manner that is beneficial to its members. At the same time, EPGP has duties to manage our partnership in a manner that is beneficial to us. Therefore, EPGP's duties to us may conflict with the duties of its officers and directors to its members. Such conflicts may include, among others, the following:

- neither our partnership agreement nor any other agreement requires EPGP or EPCO to pursue a business strategy that favors us;
- decisions of EPGP regarding the amount and timing of asset purchases and sales, cash expenditures, borrowings, issuances of additional units and reserves in any quarter may affect the level of cash available to pay quarterly distributions to unitholders and EPGP;
- under our partnership agreement, EPGP determines which costs incurred by it and its affiliates are reimbursable by us;
- EPGP is allowed to resolve any conflicts of interest involving us and EPGP and its affiliates;
- EPGP is allowed to take into account the interests of parties other than us, such as EPCO, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to unitholders;
- any resolution of a conflict of interest by EPGP not made in bad faith and that is fair and reasonable to us shall be binding on the partners and shall not be a breach of our partnership agreement;
- affiliates of EPGP, including TEPPCO, may compete with us in certain circumstances;
- EPGP has limited its liability and reduced its fiduciary duties and has also restricted the remedies available to our unitholders for actions that might, without the limitations, constitute breaches of fiduciary duty. As a result of purchasing our units, you are deemed to consent to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law;

- we do not have any employees and we rely solely on employees of EPCO and its affiliates;

- in some instances, EPGP may cause us to borrow funds in order to permit the payment of distributions, even if the purpose or effect of the borrowing is to make incentive distributions;

- our partnership agreement does not restrict EPGP from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;

- EPGP intends to limit its liability regarding our contractual and other obligations and, in some circumstances, may be entitled to be indemnified by us;

- EPGP controls the enforcement of obligations owed to us by our general partner and its affiliates; and

- EPGP decides whether to retain separate counsel, accountants or others to perform services for us.

We have significant business relationships with entities controlled by Dan L. Duncan, including EPCO and TEPPCO. For detailed information on these relationships and related transactions with these entities, see Item 13 included within this annual report.

Unitholders have limited voting rights and are not entitled to elect our general partner or its directors, which could lower the trading price of our common units. In addition, even if unitholders are dissatisfied, they cannot easily remove our general partner.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders did not elect EPGP or its directors and will have no right to elect our general partner or its directors on an annual or other continuing basis. The Board of Directors of our general partner, including the independent directors, is chosen by the owners of the general partner and not by the unitholders.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they currently have no practical ability to remove EPGP or its officers or directors. EPGP may not be removed except upon the vote of the holders of at least 60.0% of our outstanding units voting together as a single class. Because affiliates of EPGP currently own approximately 34.0% of our outstanding common units, the removal of EPGP as our general partner is highly unlikely without the consent of both EPGP and its affiliates. As a result of this provision, the trading price of our common units may be lower than other forms of equity ownership because of the absence or reduction of a takeover premium in the trading price.

Our partnership agreement restricts the voting rights of unitholders owning 20.0% or more of our common units.

Unitholders' voting rights are further restricted by a provision in our partnership agreement stating that any units held by a person that owns 20.0% or more of any class of our common units then outstanding, other than our general partner and its affiliates, cannot be voted on any matter. In addition, our partnership agreement contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting our unitholders' ability to influence the manner or direction of our management. As a result of this provision, the trading price of our common units may be lower than other forms of equity ownership because of the absence or reduction of a takeover premium in the trading price.

EPGP has a limited call right that may require common unitholders to sell their units at an undesirable time or price.

If at any time EPGP and its affiliates own 85.0% or more of the common units then outstanding, EPGP will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons at a price not less than the then current market price. As a result, common unitholders may be required to sell their common units at an undesirable time or price and may therefore not receive any return on their investment. They may also incur a tax liability upon a sale of their units.

Our common unitholders may not have limited liability if a court finds that limited partner actions constitute control of our business.

Under Delaware law, common unitholders could be held liable for our obligations to the same extent as a general partner if a court determined that the right of limited partners to remove our general partner or to take other action under our partnership agreement constituted participation in the "control" of our business.

Under Delaware law, our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those of our contractual obligations that are expressly made without recourse to our general partner.

The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the states in which we do business. You could have unlimited liability for our obligations if a court or government agency determined that:

- we were conducting business in a state, but had not complied with that particular state's partnership statute; or

- your right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constituted "control" of our business.

Unitholders may have liability to repay distributions.

Under certain circumstances, our unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act (the "Delaware Act"), we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. A purchaser of common units who becomes a limited partner is liable for the obligations of the transferring limited partner to make contributions to the partnership that are known to such purchaser of common units at the time it became a limited partner and for unknown obligations if the liabilities could be determined from our partnership agreement.

Our general partner's interest in us and the control of our general partner may be transferred to a third party without unitholder consent.

Our general partner, in accordance with our partnership agreement, may transfer its general partner interest without the consent of unitholders. In addition, our general partner may transfer its general partner interest to a third party in a merger or consolidation or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of Enterprise GP Holdings or its affiliates to transfer their equity interests in our general partner to a third party. The new equity owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with their own choices and to influence the decisions taken by the board of directors and officers of our general partner.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service were to treat us as a corporation or if we were to become subject to a material amount of entity-level taxation for state tax purposes, then our cash available for distribution to our common unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service ("IRS") on this matter.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35.0%. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distributions to our common unitholders would be substantially reduced. Thus, treatment of us as a corporation would result in a material reduction in the after-tax return to our common unitholders, likely causing a substantial reduction in the value of our common units.

Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to a material amount of entity level taxation. In addition, because of widespread state budget deficits and other reasons, several states (including Texas) are evaluating ways to enhance state-tax collections. For example, with respect to tax reports due on or after January 1, 2008, our operating subsidiaries are subject to the Revised Texas Franchise Tax on that portion of their revenue generated in Texas. Specifically, the Revised Texas Franchise Tax is imposed at a maximum effective rate of 0.7% of the operating subsidiaries' gross revenue that is apportioned to Texas. If any additional state were to impose an entity-level tax upon us or our operating subsidiaries, the cash available for distribution to our common unitholders would be reduced.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the U.S. federal income tax laws and interpretations thereof could make it more difficult or impossible to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes that is not taxable as a corporation, or Qualifying Income Exception, affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income and adversely affect an investment in our common units. For example, in response to certain recent developments, members of Congress are considering substantive changes to the definition of qualifying income under Section 7704(d) of the Internal Revenue Code. It is possible that these legislative efforts could result in changes to the existing U.S. tax laws that affect publicly traded partnerships, including us. Modifications to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively. We are unable to predict whether any changes will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to successfully challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A successful IRS contest of the federal income tax positions we take may adversely impact the market for our common units, and the costs of any contests will be borne by our unitholders and our general partner.

The IRS may adopt positions that differ from the positions we take, even positions taken with advice of counsel. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which our common units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will be borne indirectly by our unitholders and our general partner.

Even if our common unitholders do not receive any cash distributions from us, they will be required to pay taxes on their share of our taxable income.

Common unitholders will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income whether or not they receive any cash distributions from us. Our common unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability which results from their share of our taxable income.

Tax gain or loss on the disposition of our common units could be different than expected.

If a common unitholder sells its common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized and the unitholder's tax basis in those common units. Prior distributions to a unitholder in excess of the total net taxable income a unitholder is allocated for a common unit, which decreased the unitholder's tax basis in that common unit, will, in effect, become taxable income to the unitholder if the common unit is sold at a price greater than the unitholder's tax basis in that common unit, even if the price the unitholder receives is less than the unitholder's original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to a unitholder.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investments in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), other retirement plans and non-U.S. persons, raise issues unique to them. For example, virtually all of our income allocated to unitholders who are organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income.

We will treat each purchaser of our common units as having the same tax benefits without regard to the units purchased. The IRS may challenge this treatment, which could adversely affect the value of our common units.

Because we cannot match transferors and transferees of common units, we adopt depreciation and amortization positions that may not conform with all aspects of applicable Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to a common unitholder. It also could affect the timing of these tax benefits or the amount of gain from a sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to the common unitholder's tax returns.

Our common unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of an investment in our common units.

In addition to federal income taxes, our common unitholders will likely be subject to other taxes, including state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property. Our common unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, they may be subject to penalties for failure to comply with those requirements. We may own property or conduct business in other states or foreign countries in the future. It is the responsibility of the common unitholder to file all federal, state and local tax returns.

The sale or exchange of 50.0% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50.0% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between EPGP and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of our common units.

When we issue additional common units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and EPGP. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and EPGP, which may be unfavorable to such unitholders. Moreover, subsequent purchasers of common units may have a greater portion of their Internal Revenue code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between EPGP and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from a unitholder's sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to the unitholder's tax returns.

Item 1B. *Unresolved Staff Comments*.

None.

Item 3. ***Legal Proceedings*.**

On occasion, we or our unconsolidated affiliates are named as defendants in litigation relating to our normal business activities, including regulatory and environmental matters. Although we are insured against various business risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings as a result of our ordinary business activities. We are unaware of any significant litigation, pending or threatened, that could have a significant adverse effect on our financial position, results of operations or cash flows. For detailed information regarding our legal proceedings, see Note 20 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Item 4. ***Submission of Matters to a Vote of Security Holders***.

None.

PART II

Item 5. ***Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities.***

Market Information and Cash Distributions

Our common units are listed on the NYSE under the ticker symbol "EPD." As of February 2, 2009, there were approximately 988 unitholders of record of our common units. The following table presents the high and low sales prices for our common units during the periods indicated (as reported by the NYSE Composite Transaction Tape) and the amount, record date and payment date of the quarterly cash distributions we paid on each of our common units.

	Price Ranges		Cash Distribution History		
	High	Low	Per Unit	Record Date	Payment Date
2007					
1st Quarter	$32.750	$28.060	$0.4750	Apr. 30, 2007	May 10, 2007
2nd Quarter	$33.350	$30.220	$0.4825	Jul. 31, 2007	Aug. 9, 2007
3rd Quarter	$33.700	$26.136	$0.4900	Oct. 31, 2007	Nov. 8, 2007
4th Quarter	$32.450	$29.920	$0.5000	Jan. 31, 2008	Feb. 7, 2008
2008					
1st Quarter	$32.630	$26.750	$0.5075	Apr. 30, 2008	May 7, 2008
2nd Quarter	$32.640	$29.040	$0.5150	Jul. 31, 2008	Aug. 7, 2008
3rd Quarter	$30.070	$22.580	$0.5225	Oct. 31, 2008	Nov. 12, 2008
4th Quarter	$26.300	$16.000	$0.5300	Jan. 30, 2009	Feb. 9, 2009

The quarterly cash distributions shown in the table above correspond to cash flows for the quarters indicated. The actual cash distributions (i.e., the payments made to our partners) occur within 45 days after the end of such quarter. We expect to fund our quarterly cash distributions to partners primarily with cash provided by operating activities. For additional information regarding our cash flows from operating activities, see "Liquidity and Capital Resources" included under Item 7 of this annual report. Although the payment of cash distributions is not guaranteed, we expect to continue to pay comparable cash distributions in the future.

In January 2009, we sold 10,590,000 common units (including an over-allotment of 990,000 common units) to the public at an offering price of $22.20 per unit. We used the net offering proceeds of $225.6 million to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility, which may be reborrowed to fund capital expenditures and other growth projects, and for general partnership purposes.

Recent Sales of Unregistered Securities

There were no sales of unregistered equity securities during 2008.

Common Units Authorized for Issuance Under Equity Compensation Plan

See "Securities Authorized for Issuance Under Equity Compensation Plans" under Item 12 of this annual report, which is incorporated by reference into this Item 5.

Issuer Purchases of Equity Securities

We have not repurchased any of our common units since 2002. In December 1998, we announced a common unit repurchase program whereby we, together with certain affiliates, intended to repurchase up to 2,000,000 of our common units for the purpose of granting options to management and key employees (amount adjusted for the 2-for-1 unit split in May 2002). As of February 2, 2009, we and our affiliates could repurchase up to 618,400 additional common units under this repurchase program.

The following table summarizes our repurchase activity during 2008 in connection with other arrangements:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of of Units Purchased as Part of Publicly Announced Plans	Maximum Number of Units That May Yet Be Purchased Under the Plans
May 2008	21,413 (1)	$30.37	--	--
August 2008	4,940 (2)	$29.19	--	--
September 2008	4,565 (3)	$25.77	--	--
October 2008	54,328 (4)	$18.39	--	--

(1) Of the 67,500 restricted unit awards that vested in May 2008 and converted to common units, 21,413 of these units were sold back to the partnership by employees to cover related withholding tax requirements.

(2) Of the 28,650 restricted unit awards that vested in August 2008 and converted to common units, 4,940 of these units were sold back to the partnership by employees to cover related withholding tax requirements.

(3) Of the 16,500 restricted unit awards that vested in September 2008 and converted to common units, 4,565 of these units were sold back to the partnership by employees to cover related withholding tax requirements.

(4) Of the 165,958 restricted unit awards that vested in October 2008 and converted to common units, 54,328 of these units were sold back to the partnership by employees to cover related withholding tax requirements.

Item 6. *Selected Financial Data.*

The following table presents selected historical consolidated financial data of our partnership. This information has been derived from and should be read in conjunction with the audited financial statements. In addition, information regarding our results of operations and liquidity and capital resources can be found under Item 7 of this annual report. As presented in the table, amounts are in thousands (except per unit data).

	For the Year Ended December 31,				
	2008	**2007**	**2006**	**2005**	**2004**
Operating results data: (1)					
Revenues	$ 21,905,656	$ 16,950,125	$ 13,990,969	$ 12,256,959	$ 8,321,202
Income from continuing operations (2)	$ 954,021	$ 533,674	$ 599,683	$ 423,716	$ 257,480
Income per unit from continuing operations:					
Basic and Diluted	$ 1.85	$ 0.96	$ 1.22	$ 0.92	$ 0.83
Other financial data:					
Distributions per common unit (3)	$ 2.0750	$ 1.9475	$ 1.825	$ 1.698	$ 1.540

	As of December 31,				
	2008	**2007**	**2006**	**2005**	**2004**
Financial position data: (1)					
Total assets	$ 17,957,535	$ 16,608,007	$ 13,989,718	$ 12,591,016	$ 11,315,461
Long-term and current maturities of debt (4)	$ 9,108,410	$ 6,906,145	$ 5,295,590	$ 4,833,781	$ 4,281,236
Partners' equity (5)	$ 6,084,988	$ 6,131,649	$ 6,480,233	$ 5,679,309	$ 5,328,785
Total units outstanding (excluding treasury) (5)	441,435	435,297	432,408	389,861	364,786

(1) In general, our historical operating results and financial position have been affected by numerous acquisitions since 2002. Our most significant transaction to date was the GulfTerra Merger, which was completed on September 30, 2004. The aggregate value of the total consideration we paid or issued to complete the GulfTerra Merger was approximately $4 billion. We accounted for the GulfTerra Merger and our other acquisitions using purchase accounting; therefore, the operating results of these acquired entities are included in our financial results prospectively from their respective acquisition dates.

(2) Amounts presented for the years ended December 31, 2006, 2005 and 2004 are before the cumulative effect of accounting changes.

(3) Distributions per common unit represent declared cash distributions with respect to the four fiscal quarters of each period presented.

(4) In general, the balances of our long-term and current maturities of debt have increased over time as a result of financing all or a portion of acquisitions and other capital spending.

(5) We regularly issue common units through underwritten public offerings and, less frequently, in connection with acquisitions or other transactions. The September 2004 issuance of 104.5 million common units in connection with the GulfTerra Merger being our largest. For additional information regarding our partners' equity and unit history, see Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Item 7. ***Management's Discussion and Analysis of Financial Condition and Results of Operations*****.**

For the years ended December 31, 2008, 2007 and 2006.

The following information should be read in conjunction with our consolidated financial statements and our accompanying notes. Our discussion and analysis includes the following:

- Cautionary Note Regarding Forward-Looking Statements.
- Significant Relationships Referenced in this Discussion and Analysis.
- Overview of Business.
- General Outlook for 2009.
- Recent Developments – Discusses significant developments during the year ended December 31, 2008.
- Results of Operations – Discusses material year-to-year variances in our Statements of Consolidated Operations.
- Liquidity and Capital Resources – Addresses available sources of liquidity and capital resources and includes a discussion of our capital spending program.
- Critical Accounting Policies and Estimates.
- Other Items – Includes information related to contractual obligations, off-balance sheet arrangements, related party transactions, recent accounting pronouncements and other matters.

As generally used in the energy industry and in this discussion, the identified terms have the following meanings:

/d	= per day
BBtus	= billion British thermal units
Bcf	= billion cubic feet
MBPD	= thousand barrels per day
MMBbls	= million barrels
MMBtus	= million British thermal units
MMcf	= million cubic feet

Our financial statements have been prepared in accordance with U.S. generally accepted accounting principles ("GAAP").

Cautionary Note Regarding Forward-Looking Statements

This discussion contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "estimate," "forecast," "intend," "could," "should," "will," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions as described in more detail in Item 1A of this annual report. If one or more of these risks or uncertainties materialize, or if underlying *assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements.*

Significant Relationships Referenced in this Discussion and Analysis

Unless the context requires otherwise, references to “we,” “us,” “our,” or “Enterprise Products Partners” are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries.

References to “EPO” mean Enterprise Products Operating LLC as successor in interest by merger to Enterprise Products Operating L.P., which is a wholly owned subsidiary of Enterprise Products Partners through which Enterprise Products Partners conducts substantially all of its business.

References to “Duncan Energy Partners” mean Duncan Energy Partners L.P., which is a consolidated subsidiary of EPO. Duncan Energy Partners is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange (“NYSE”) under the ticker symbol “DEP.” References to “DEP GP” mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and is wholly owned by EPO.

References to “EPGP” mean Enterprise Products GP, LLC, which is our general partner.

References to “Enterprise GP Holdings” mean Enterprise GP Holdings L.P., a publicly traded affiliate, the units of which are listed on the NYSE under the ticker symbol “EPE.” Enterprise GP Holdings owns EPGP. References to “EPE Holdings” mean EPE Holdings, LLC, which is the general partner of Enterprise GP Holdings.

References to “TEPPCO” mean TEPPCO Partners, L.P., a publicly traded affiliate, the common units of which are listed on the NYSE under the ticker symbol “TPP.” References to “TEPPCO GP” refer to Texas Eastern Products Pipeline Company, LLC, which is the general partner of TEPPCO and is wholly owned by Enterprise GP Holdings.

References to “Energy Transfer Equity” mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. (“ETP”). Energy Transfer Equity is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol “ETE.” The general partner of Energy Transfer Equity is LE GP, LLC (“LE GP”). On May 7, 2007, Enterprise GP Holdings acquired non-controlling interests in both LE GP and Energy Transfer Equity. Enterprise GP Holdings accounts for its investments in LE GP and Energy Transfer Equity using the equity method of accounting.

References to “Employee Partnerships” mean EPE Unit L.P. (“EPE Unit I”), EPE Unit II, L.P. (“EPE Unit II”), EPE Unit III, L.P. (“EPE Unit III”), Enterprise Unit L.P. (“Enterprise Unit”) and EPCO Unit L.P. (“EPCO Unit”), collectively, all of which are private company affiliates of EPCO, Inc.

References to “EPCO” mean EPCO, Inc. and its wholly owned private company affiliates, which are related parties to all of the foregoing named entities.

We, EPO, Duncan Energy Partners, DEP GP, EPGP, Enterprise GP Holdings, EPE Holdings, TEPPCO and TEPPCO GP are affiliates under the common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO.

Overview of Business

We are a North American midstream energy company providing a wide range of services to producers and consumers of natural gas, natural gas liquids (“NGLs”), crude oil and certain petrochemicals. In addition, we are an industry leader in the development of pipeline and other midstream energy infrastructure in the continental United States and Gulf of Mexico. We are a publicly traded Delaware limited partnership formed in 1998, the common units of which are listed on the NYSE under the ticker symbol "EPD."

Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States, Canada and the Gulf of Mexico with domestic consumers and international markets. We have four reportable business segments: NGL Pipelines & Services; Onshore Natural Gas Pipelines & Services; Offshore Pipelines & Services; and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

We conduct substantially all of our business through EPO. We are owned 98.0% by our limited partners and 2.0% by our general partner, EPGP. EPGP is owned 100.0% by Enterprise GP Holdings.

General Outlook for 2009

The current global recession and financial crisis have impacted energy companies generally. The recession and related slowdown in economic activity has reduced demand for energy and related products, which in turn has generally led to significant decreases in the prices of crude oil, natural gas and NGLs. The financial crisis has resulted in the effective insolvency, liquidation or government intervention for a number of financial institutions, investment companies, hedge funds and highly leveraged industrial companies. This has had an adverse impact on the prices of debt and equity securities that has generally increased the cost and limited the availability of debt and equity capital.

Commercial Outlook

In 2008, there was significant volatility in the prices of refined products, crude oil, natural gas and NGLs. For example, the price of West Texas Intermediate crude oil ranged from a high near $147 per barrel in mid-2008 to $35 per barrel in January 2009; while the price of natural gas at the Henry Hub ranged from a high of over $13.00 per MMBtu in mid-2008 to $5.00 per MMBtu in January 2009. On a composite basis, the average price of NGLs declined from $1.68 per gallon for the third quarter of 2008 to $0.74 per gallon for the fourth quarter of 2008. The decrease in energy commodity prices combined with higher costs of capital have led many crude oil and natural gas producers to reconsider their drilling budgets for 2009. As a midstream energy company, we provide services for producers and consumers of natural gas, NGLs, crude oil and certain petrochemicals. The products that we process, sell or transport are principally used as fuel for residential, agricultural and commercial heating; feedstocks in petrochemical manufacturing; and in the production of motor gasoline.

The decrease in energy commodity prices has caused many oil and natural gas producers, which include many of our customers, to reduce their drilling budgets in 2009. This has resulted in a substantial reduction in the number of drilling rigs operating in the United States as surveyed by Baker Hughes Incorporated. The U.S. operating rig count decreased from a peak of 2,031 rigs in September 2008 to approximately 1,300 in February 2009. We expect oil and gas producers in our operating areas to reduce their drilling activity to varying degrees, which may lead to lower crude oil, natural gas and NGL production growth in the near term and, as a result, lower transportation, processing and marketing volumes for us than would have otherwise been the case.

In our natural gas processing business, we hedged approximately 80% of our equity NGL production margins for 2008 to mitigate the commodity price risk associated with these volumes. We have hedged approximately 67% of our expected equity NGL production margins for 2009. Since the hedges were consummated at prices that are significantly higher than current levels, we are expected to be partially insulated from lower natural gas processing margins in 2009.

The recession has reduced demand for midstream energy services and products by industrial customers. In the fourth quarter of 2008, the petrochemical industry experienced a dramatic destocking of inventories, which reduced demand for purity NGL products such as ethane, propane and normal butane. We expect that petrochemical demand will strengthen in early 2009 and have starting seeing signs of such demand through February 2009 as petrochemical customers have begun to restock their depleted inventories. This trend is also evidenced by slightly higher operating rates of U.S. ethylene crackers, which averaged approximately 70% of capacity in February 2009 as compared to 56% in December 2008. Four additional ethylene crackers were expected to recommence operations in February 2009. The average utilization rate for ethylene crackers in 2008 was approximately 80%. Based on currently available information, we expect that the operating rates of U.S. ethylene crackers will approximate 80% of capacity in 2009. We expect that crude oil prices will rebound from recent lows in the second half of 2009. As a result, we believe the petrochemical industry will continue to prefer NGL feedstocks over crude-based alternatives such as naphtha. In general, when the price of crude oil rises relative to that of natural gas, NGLs become more attractive as a source of feedstocks for the petrochemical industry.

The reduction in near-term demand for crude oil and NGLs has created a contango market (i.e., a market in which the price of a commodity is higher in future months than the current spot price) for these products, which, in turn, we are benefiting from through an increase in revenues earned by our storage assets in Mont Belvieu, Texas.

Liquidity Outlook

Debt and equity capital markets have also experienced significant recent volatility. The major U.S. and international equity market indices experienced significant losses in 2008, including losses of approximately 38% and 34% for the S&P 500 and Dow Jones Industrial Average, respectively. Likewise, the Alerian MLP Index, which is a recognized major index for publicly traded partnerships, lost approximately 42% of its value. The contraction in credit available to and investor redemptions of holdings in certain investment companies and hedge funds exacerbated the selling pressure and volatility in both the debt and equity capital markets. This has resulted in a higher cost of debt and equity capital for the public and private sector. Near term demand for equity securities through follow on offerings, including our common units, may be reduced due to the recent problems encountered by investment companies and hedge funds, both of which significantly participated in equity offerings over the past few years.

While the cost of capital has increased, we have demonstrated our ability to access the debt and equity capital markets during this distressed period. In December 2008, we issued $500.0 million of 9.75% senior notes. The higher cost of capital is evident when you compare the interest rate of the December 2008 senior notes offering to the $400.0 million of 5.65% senior notes that we issued in March 2008. On a positive note, our indicative cost of long-term borrowing has improved approximately 250 basis points in early 2009 in conjunction with the recent improvement in the debt capital markets. We believe that we will be able to either access the capital markets or utilize availability under our long-term multi-year revolving credit facility to refinance our $717.6 million of debt obligations that mature in 2009. In January 2009, we issued approximately 10.6 million of our common units at an effective annual distribution yield of 9.5%. Net offering proceeds of $225.6 million were used to reduce borrowings and for general partnership purposes.

The increase in the cost of capital has caused us to prioritize our respective internal growth projects to select those with higher rates of return. However, consistent with our business strategies, we continuously evaluate possible acquisitions of assets that would complement our current operations. Given the current state of the credit markets, we believe competition for such assets has decreased, which may result in opportunities for us to acquire assets at attractive prices that would be accretive to our partners and expand our portfolio of midstream energy assets.

Based on information currently available, we estimate that our capital spending for property, plant and equipment in 2009 will approximate $1.00 billion, which includes $820.0 million for growth capital projects and $180.0 million for sustaining capital expenditures. The 2009 forecast amounts for growth capital projects include amounts that are expected to be spent on the Texas Offshore Port System. See "Recent Developments – Texas Offshore Port System" for additional information regarding this joint venture.

We expect four of our significant construction projects to be completed and the assets placed into service during the first half of 2009. These projects include (i) the expansion of the Meeker natural gas processing plant, which began operations in February 2009, (ii) the Exxon Mobil central treating facility, (iii) the Sherman Extension natural gas pipeline, and (iv) the Shenzi Crude Oil Pipeline in the Gulf of Mexico. Substantially all of the financing to fund these projects has been completed. In 2009, we expect these projects to contribute significant new sources of revenue, operating income and cash flow from operations.

Hurricanes Gustav and Ike damaged a number of energy-related assets onshore and offshore along the Texas and Louisiana Gulf Coast in the summer of 2008, including certain of our offshore pipelines and platforms. Repairs are being completed on our affected assets and they are expected to be ready to return to service once third party production fields return to operational status over the course of 2009.

A few of our customers have experienced severe financial problems leading to a significant impact on their creditworthiness. These financial problems are rooted in various factors including the significant use of debt, current financial crises, economic recession and changes in commodity prices. We are working to implement, to the extent allowable under applicable contracts, tariffs and regulations, prepayments and other security requirements, such as letters of credit, to enhance our respective credit position relating to amounts owed to us by certain customers. We cannot provide assurance that one or more of our customers will not default on their obligations to us or that such a default or defaults will not have a material adverse effect on our consolidated financial position, results of operations, or cash flows; however, we believe that we have provided adequate allowances for such customers.

We expect our proactive approach to funding capital spending and other partnership needs, combined with sufficient trade credit to operate our businesses efficiently, and available borrowing capacity under their credit facilities, to provide us with a foundation to meet our anticipated liquidity and capital requirements in 2009. We also believe that we will be able to access the capital markets in 2009 to maintain financial flexibility. Based on information currently available to us, we believe that we will maintain our investment grade credit ratings and meet our loan covenant obligations in 2009.

Recent Developments

The following information highlights our significant developments since January 1, 2008 through the date of this filing.

Enterprise Products Partners Issues $225.6 million of Common Units

In January 2009, Enterprise Products Partners sold 10,590,000 common units representing limited partner interests (including an over-allotment of 990,000 common units) to the public at an offering price of $22.20 per unit. Net offering proceeds of $225.6 million were used to reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

High Island Offshore System Natural Gas Pipeline Resumes Operations

In December 2008, repairs were completed on the High Island Offshore System ("HIOS") pipeline that was severed in September 2008 during Hurricane Ike. Federal regulators, after approving our inspection and start-up procedures, authorized the partnership to resume full service on HIOS. The pipeline has the capacity to transport up to 1.8 Bcf/d of natural gas.

Operations Begin at White River Hub

In December 2008, we and Questar Pipeline Company ("Questar"), a subsidiary of Questar Corp., announced that service had begun on the White River Hub. Located in Rio Blanco County, Colo., the White River Hub currently connects our natural-gas processing plant at Meeker with four interstate natural gas pipelines: Rockies Express Pipeline LLC; Questar; Northwest Pipeline GP (including the Williams Willow Creek processing plant, which is currently under construction); and TransColorado Gas

Transmission Company. Two more interstate pipelines, the Wyoming Interstate Company and Colorado Interstate Gas systems, are expected to be connected during the first quarter of 2009.

Sale of Interest in Companies to Duncan Energy Partners

In December 2008, Duncan Energy Partners acquired controlling equity interests in three midstream energy companies from affiliates of EPO in a transaction valued at $730.0 million. Duncan Energy Partners acquired a 51.0% membership interest in Enterprise Texas Pipeline LLC ("Enterprise Texas"); a 51.0% general partnership interest in Enterprise Intrastate LP ("Enterprise Intrastate"); and a 66.0% general partnership interest in Enterprise GC, LP ("Enterprise GC"). In the aggregate, these companies own more than 8,000 miles of natural gas pipelines with 5.6 Bcf/d of capacity; a leased natural gas storage facility with 6.8 Bcf of storage capacity; more than 1,000 miles of NGL pipelines; approximately 18 MMBbls of leased NGL storage capacity; and two NGL fractionators with a combined fractionation capacity of 87 MBPD. All of these assets are located in Texas. As consideration for this dropdown transaction, EPO received 37,333,887 Class B units valued at $449.5 million and $280.5 million in cash from Duncan Energy Partners. The Class B limited partner units automatically converted to common units of Duncan Energy Partners on February 1, 2009. For additional information regarding this transaction, see "Other Items – Duncan Energy Partners Transactions" within this Item 7

EPO Issues $500.0 Million of Senior Notes

In December 2008, EPO sold $500.0 million in principal amount of 9.75% fixed-rate, unsecured senior notes due January 2014 ("Senior Notes O"). Net proceeds from this offering were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes. For additional information regarding this issuance of debt, see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

EPO Executes $592.6 Million of Credit Facilities

In November 2008, EPO executed two senior unsecured credit facilities that provide the partnership with $592.6 million of incremental borrowing capacity. The facilities are comprised of a $375.0 million credit facility maturing in November 2009 and a 20.7 billion yen (approximately $217.6 million U.S. dollar equivalent) term loan maturing in March 2009. The Japanese term loan has a funded cost of approximately 4.93%, including the cost of related foreign exchange currency swaps. For additional information regarding these issuances of debt, see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Texas Offshore Port System

In August 2008, we, together with TEPPCO and Oiltanking Holding Americas, Inc. ("Oiltanking"), announced the formation of the Texas Offshore Port System, a joint venture to design, construct, operate and own a Texas offshore crude oil port and a related onshore pipeline and storage system that would facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. Demand for such projects is being driven by planned and expected refinery expansions along the Gulf Coast, expected increases in shipping traffic and operating limitations of regional ship channels.

The joint venture's primary project, referred to as "TOPS," includes (i) an offshore port (which will be located approximately 36 miles from Freeport, Texas), (ii) an onshore storage facility with approximately 3.9 million barrels of crude oil storage capacity, and (iii) an 85-mile crude oil pipeline system having a transportation capacity of up to 1.8 million barrels per day, that will extend from the offshore port to a storage facility near Texas City, Texas. The joint venture's complementary project, referred to as the Port Arthur Crude Oil Express (or "PACE") will transport crude oil from Texas City, including crude oil from TOPS, and will consist of a 75-mile pipeline and 1.2 million barrels of crude oil storage capacity in the Port Arthur, Texas area. Development of the TOPS and PACE projects is supported by long-term contracts with affiliates of Motiva Enterprises LLC ("Motiva") and Exxon Mobil Corporation

("Exxon Mobil"), which have committed a combined 725 MBPD of crude oil to the projects. The timing of the construction and related capital costs of the TOPS and PACE projects will be affected by the acquisition of requisite permits.

We, TEPPCO and Oiltanking each own, through our respective subsidiaries, a one-third interest in the joint venture. The aggregate cost of the TOPS and PACE projects is expected to be approximately $1.8 billion (excluding capitalized interest), with the majority of such capital expenditures currently expected to occur in 2010 and 2011. We and TEPPCO have each guaranteed up to approximately $700.0 million, which includes a contingency amount for potential cost overruns, of the capital contribution obligations of our respective subsidiary partners in the joint venture. As of December 31, 2008, our investment in the Texas Offshore Port System was $35.9 million.

Acquisition of Remaining Interest in Dixie

In August 2008, we acquired the remaining 25.8% ownership interest in Dixie Pipeline Company ("Dixie") for $57.1 million. As a result of this transaction, we own 100.0% of Dixie, which owns a 1,371-mile pipeline system that delivers NGLs (primarily propane) to customers along the U.S. Gulf Coast and southeastern United States.

Reorganization of Commercial Management Team

In July 2008, Mr. A. J. Teague, Executive Vice President, was elected as a Director to the Boards of both our general partner and that of Duncan Energy Partners and as Chief Commercial Officer responsible for managing all of the commercial activities of the two partnerships. In connection with Mr. Teague's appointment as Chief Commercial Officer, certain members of our senior management team were realigned to report to Mr. Teague. Mr. Teague will continue to report to Michael A. Creel, President and Chief Executive Officer ("CEO") of Enterprise Products Partners.

Independence Trail and Hub Resume Operations

In April 2008, production at the Independence Hub natural gas platform was shut-in due to a leak in the flex-joint assembly where the Independence Trail export pipeline connects to the platform. In July 2008, repairs were completed and the Independence Hub platform and Trail pipeline returned to operation. Our Independence Trail export pipeline recorded $17.0 million of expense associated with the flex-joint repairs. We have submitted a claim with our insurance carriers regarding the flex-joint repair costs. To the extent that we receive cash proceeds from this claim in the future, such amounts would be recorded as income in the period of receipt.

EPO Issues $1.10 Billion of Senior Notes

In April 2008, EPO sold $400.0 million in principal amount of 5.65% fixed-rate, unsecured senior notes due April 2013 ("Senior Notes M") and $700.0 million in principal amount of 6.50% fixed-rate, unsecured senior notes due January 2019 ("Senior Notes N"). Net proceeds from this offering were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility. For additional information regarding this issuance of debt, see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Duncan Energy Partners' Shelf Registration Statement

In March 2008, Duncan Energy Partners filed a universal shelf registration statement with the SEC that authorized its issuance of up to $1.00 billion in debt and equity securities. As of February 2, 2008, Duncan Energy Partners has issued $0.5 million in equity securities under this registration statement.

Pioneer Cryogenic Natural Gas Processing Facility Commences Operations

In February 2008, we commenced operations of the Pioneer cryogenic natural gas processing facility. Located near the Opal Hub in southwestern Wyoming, this new facility is designed to process up to 700 MMcf/d of natural gas and extract as much as 30 MBPD of NGLs. We intend to maintain the operational capability of our Pioneer silica gel natural gas processing plant, which is located adjacent to the Pioneer cryogenic plant, as a back-up to provide producers with additional assurance of our processing capability at the complex. NGLs extracted at our Pioneer complex are transported on our Mid-America Pipeline System and ultimately to our Hobbs and Mont Belvieu NGL fractionators.

In late March 2008, operations at our Pioneer cryogenic natural gas processing facility were temporarily suspended following a release of natural gas and subsequent fire. No injuries resulted from the incident, which was restricted to a small area within the plant. The facility resumed operations in April 2008.

Results of Operations

We have four reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Offshore Pipelines & Services and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by senior management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered as an alternative to GAAP operating income.

We define total segment gross operating margin as consolidated operating income before (i) depreciation, amortization and accretion expense; (ii) operating lease expenses for which we do not have the payment obligation; (iii) gains and losses from asset sales and related transactions; and (iv) general and administrative costs. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest, extraordinary charges and the cumulative effect of change in accounting principle. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intersegment and intrasegment transactions. Intercompany accounts and transactions are eliminated in consolidation.

We include equity in earnings of unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers and/or suppliers. This method of operation also enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand alone basis. Many of these businesses perform supporting or complementary roles to our other business operations.

Our consolidated gross operating margin amounts include the gross operating margin amounts of Duncan Energy Partners on a 100.0% basis. Volumetric data associated with the operations of Duncan Energy Partners are also included on a 100.0% basis in our consolidated statistical data.

For additional information regarding our business segments, see Note 16 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Selected Price and Volumetric Data

The following table illustrates selected annual and quarterly industry index prices for natural gas, crude oil and selected NGL and petrochemical products for the periods presented.

	Natural Gas, $/MMBtu	Crude Oil, $/barrel	Ethane, $/gallon	Propane, $/gallon	Normal Butane, $/gallon	Isobutane, $/gallon	Natural Gasoline, $/gallon	Polymer Grade Propylene, $/pound	Refinery Grade Propylene, $/pound
	(1)	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
2006 Averages	$7.24	$66.09	$0.66	$1.01	$1.20	$1.24	$1.44	$0.47	$0.41
2007 Averages	$6.86	$72.30	$0.79	$1.21	$1.42	$1.49	$1.68	$0.52	$0.47
2008									
1st Quarter	$8.03	$97.91	$1.01	$1.47	$1.80	$1.87	$2.12	$0.61	$0.54
2nd Quarter	$10.94	$123.88	$1.05	$1.70	$2.05	$2.08	$2.64	$0.70	$0.67
3rd Quarter	$10.25	$118.01	$1.09	$1.68	$1.97	$1.99	$2.52	$0.78	$0.66
4th Quarter	$6.95	$58.32	$0.42	$0.80	$0.90	$0.96	$1.09	$0.37	$0.22
2008 Averages	$9.04	$99.53	$0.89	$1.41	$1.68	$1.72	$2.09	$0.62	$0.52

(1) Natural gas, NGL, polymer grade propylene and refinery grade propylene prices represent an average of various commercial index prices including Oil Price Information Service ("OPIS") and Chemical Market Associates, Inc. ("CMAI"). Natural gas price is representative of Henry-Hub I-FERC. NGL prices are representative of Mont Belvieu Non-TET pricing. Refinery grade propylene represents a weighted-average of CMAI spot prices. Polymer-grade propylene represents average CMAI contract pricing.

(2) Crude oil price is representative of an index price for West Texas Intermediate.

The following table presents our significant average throughput, production and processing volumetric data. These statistics are reported on a net basis, taking into account our ownership interests in certain joint ventures and reflect the periods in which we owned an interest in such operations. These statistics include volumes for newly constructed assets since the dates such assets were placed into service and for recently purchased assets since the date of acquisition.

	For the Year Ended December 31,		
	2008	**2007**	**2006**
NGL Pipelines & Services, net:			
NGL transportation volumes (MBPD)	1,819	1,666	1,577
NGL fractionation volumes (MBPD)	429	394	312
Equity NGL production (MBPD)	108	88	63
Fee-based natural gas processing (MMcf/d)	2,524	2,565	2,218
Onshore Natural Gas Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d)	7,477	6,632	6,012
Offshore Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d)	1,408	1,641	1,520
Crude oil transportation volumes (MBPD)	169	163	153
Platform natural gas processing (MMcf/d)	632	494	159
Platform crude oil processing (MBPD)	15	24	15
Petrochemical Services, net:			
Butane isomerization volumes (MBPD)	86	90	81
Propylene fractionation volumes (MBPD)	58	68	56
Octane additive production volumes (MBPD)	9	9	9
Petrochemical transportation volumes (MBPD)	108	105	97
Total, net:			
NGL, crude oil and petrochemical transportation volumes (MBPD)	2,096	1,934	1,827
Natural gas transportation volumes (BBtus/d)	8,885	8,273	7,532
Equivalent transportation volumes (MBPD) (1)	4,434	4,111	3,809

(1) Reflects equivalent energy volumes where 3.8 MMBtus of natural gas are equivalent to one barrel of NGLs.

Comparison of Results of Operations

The following table summarizes the key components of our results of operations for the periods indicated (dollars in thousands):

	For the Year Ended December 31,		
	2008	2007	2006
Revenues	$ 21,905,656	$ 16,950,125	$ 13,990,969
Operating costs and expenses	20,460,964	16,009,051	13,089,091
General and administrative costs	90,550	87,695	63,391
Equity in earnings of unconsolidated affiliates	59,104	29,658	21,565
Operating income	1,413,246	883,037	860,052
Interest expense	400,686	311,764	238,023
Provision for income taxes	26,401	15,257	21,323
Minority interest	41,376	30,643	9,079
Net income	954,021	533,674	601,155

Our gross operating margin by segment and in total is as follows for the periods indicated (dollars in thousands):

	For the Year Ended December 31,		
	2008	2007	2006
Gross operating margin by segment:			
NGL Pipelines & Services	$ 1,290,458	$ 812,521	$ 752,548
Onshore Natural Gas Pipelines & Services	411,344	335,683	333,399
Offshore Pipeline & Services	188,083	171,551	103,407
Petrochemical Services	167,584	172,313	173,095
Total segment gross operating margin	$ 2,057,469	$ 1,492,068	$ 1,362,449

For a reconciliation of non-GAAP gross operating margin to GAAP operating income and further to GAAP income before provision for income taxes, minority interest and the cumulative effect of change in accounting principles, see “Other Items – Non-GAAP Reconciliations” included within this Item 7.

The following table summarizes the contribution to revenues from each business segment (including the effects of eliminations and adjustments) during the periods indicated (dollars in thousands):

	For the Year Ended December 31,		
	2008	2007	2006
NGL Pipelines & Services:			
Sales of NGLs	$ 14,680,607	$ 11,757,895	$ 9,442,403
Sales of other petroleum and related products	2,387	3,027	2,353
Midstream services	698,957	710,447	745,187
Total	15,381,951	12,471,369	10,189,943
Onshore Natural Gas Pipelines & Services:			
Sales of natural gas	3,091,296	1,481,569	1,103,169
Midstream services	480,802	588,526	595,726
Total	3,572,098	2,070,095	1,698,895
Offshore Pipelines & Services:			
Sales of natural gas	100	101	307
Sales of other petroleum and related products	11,144	12,086	4,562
Midstream services	257,166	211,624	140,994
Total	268,410	223,811	145,863
Petrochemical Services:			
Sales of other petroleum and related products	2,593,856	2,115,429	1,873,722
Midstream services	89,341	69,421	82,546
Total	2,683,197	2,184,850	1,956,268
Total consolidated revenues	$ 21,905,656	$ 16,950,125	$ 13,990,969

Our revenues are derived from a wide customer base. During 2008, our largest customer was LyondellBasell Industries ("LBI") and its affiliates, which accounted for 9.6% of our consolidated revenues. In 2007 and 2006, our largest customer was The Dow Chemical Company and its affiliates, which accounted for 6.9% and 6.1%, respectively, of our consolidated revenues.

On January 6, 2009, LBI announced that its U.S. operations had voluntarily filed to reorganize under Chapter 11 of the U.S. Bankruptcy Code. At the time of the bankruptcy filing, we had approximately $17.3 million of credit exposure to LBI, which was reduced to approximately $10.0 million through remedies provided under certain pipeline tariffs. In addition, we are seeking to have LBI accept certain contracts and have filed claims pursuant to current Bankruptcy Court Orders that we expect will allow us to recover the majority of the remaining credit exposure.

For 2008, LBI accounted for 10.2%, or $1.6 billion, of revenues attributable to our NGL Pipelines & Services business segment and 19.2%, or $516.2 million, of revenues attributable to our Petrochemical Services business segment.

Comparison of 2008 with 2007

Revenues for 2008 were $21.91 billion compared to $16.95 billion for 2007. The $4.96 billion year-to-year increase in consolidated revenues is primarily due to higher energy commodity sales volumes and prices during 2008 relative to 2007. These factors accounted for $5.01 billion of the year-to-year increase in consolidated revenues associated with our NGL, natural gas and petrochemical marketing activities. Equity NGLs we produced at our newly constructed Meeker and Pioneer natural gas plants and sold in connection with our NGL marketing activities contributed $731.3 million of the year-to-year increase in marketing activity revenues.

Operating costs and expenses were $20.46 billion for 2008 versus $16.01 billion for 2007. The $4.45 billion year-to-year increase in consolidated operating costs and expenses is primarily due to higher cost of sales associated with our marketing activities. The cost of sales of our marketing activities increased $3.57 billion year-to-year primarily due to higher energy commodity sales volumes and prices. Likewise, the operating costs and expenses of our natural gas processing plants increased $306.3 million year-to-year primarily due to higher energy commodity prices. Consolidated operating costs and expenses attributable to newly constructed assets we placed into service after January 1, 2007 increased $414.3 million year-to-year. General and administrative costs increased $2.9 million year-to-year.

Changes in our revenues and costs and expenses year-to-year are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.40 per gallon during 2008 versus $1.19 per gallon during 2007. Our determination of the weighted-average indicative market price for NGLs is based on U.S. Gulf Coast prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production. The market price of natural gas (as measured at Henry Hub) averaged $9.04 per MMBtu during 2008 versus $6.86 per MMBtu during 2007. See "Results of Operations - Selected Price and Volumetric Data" within this Item 7 for additional historical energy commodity pricing information.

Equity in earnings from our unconsolidated affiliates was $59.1 million for 2008 compared to $29.7 million for 2007, a $29.4 million year-to-year increase. Equity in earnings from our investment in Cameron Highway Oil Pipeline Company ("Cameron Highway") increased $27.6 million year-to-year due to higher transportation volumes and lower interest expense. On a 100.0% basis, Cameron Highway had crude oil transportation volumes of 161 MBPD during 2008 compared to 88 MBPD during 2007. Equity in earnings from our investment in Jonah Gas Gathering Company ("Jonah") increased $12.1 million year-to-year. We earned a fixed 19.4% interest in Jonah during the third quarter of 2007 upon completion of certain achievements with respect to the Phase V Expansion of the Jonah Gathering System. Equity in earnings from our investment in Nemo Gathering Company, LLC ("Nemo") increased $5.0 million year-to-year due to the recognition of a non-cash impairment charge in the second quarter of 2007. Collectively, equity earnings from our other investments decreased $15.3 million year-to-year primarily due to higher repair and maintenance expenses during 2008 relative to 2007 as well as the effects of downtime and reduced volumes attributable to Hurricanes Gustav and Ike.

Operating income for 2008 was $1.41 billion compared to $883.0 million for 2007. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to the $530.2 million increase in operating income year-to-year.

Interest expense increased to $400.7 million for 2008 from $311.8 million for 2007. The $88.9 million year-to-year increase in interest expense is primarily due to our issuance of Senior Notes M and N in the second quarter of 2008 and Senior Notes L in the third quarter of 2007. Average debt principal outstanding during 2008 was $7.93 billion compared to $6.18 billion during 2007.

Provision for income taxes increased $11.1 million year-to-year primarily due to higher expenses associated with the Texas Margin Tax. The increase in expenses for the Texas Margin Tax primarily reflects a higher taxable margin in the State of Texas during 2008 relative to 2007. In addition we recognized a $4.4 million benefit with respect to the Texas Margin Tax during 2007 due to the reorganization of certain of our entities from partnerships to limited liability companies. Minority interest expense increased $10.7 million year-to-year attributable to the public unitholders of Duncan Energy Partners and third-party ownership interests in the Independence Hub platform.

As a result of items noted in the previous paragraphs, our consolidated net income increased $420.3 million year-to-year to $954.0 million for 2008 compared to $533.7 million for 2007.

In general, Hurricanes Gustav and Ike had an adverse effect across our operations in the Gulf of Mexico and along the U.S. Gulf Coast during 2008. Storm-related disruptions in natural gas, NGL and crude oil production in these regions resulted in reduced volumes available to our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which in turn caused a decrease in gross operating margin for certain operations. In addition, property damage caused by Hurricanes Gustav and Ike resulted in lower revenues due to facility downtime as well as higher operating costs and expenses at certain of our plants and pipelines. As a result of our allocated share of EPCO's insurance deductibles for windstorm coverage, gross operating margin for 2008 includes $47.9 million of repair expenses for property damage sustained by our assets as a result of the hurricanes.

We estimate that gross operating margin was reduced by $77.0 million during 2008 due to the effects of Hurricanes Gustav and Ike as a result of supply interruptions and facility downtime. For more information regarding our insurance program and claims related to these storms, see "Other Items – Insurance Matters" included within this Item 7.

The following information highlights significant year-to-year variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $1.29 billion for 2008 compared to $812.5 million for 2007. The $478.0 million year-to-year increase in segment gross operating margin is due to strong natural gas processing margins and petrochemical demand for NGLs as well as an increase in equity NGL production attributable to our Meeker and Pioneer natural gas processing facilities. Results for 2007 include $32.7 million of proceeds from business interruption insurance claims compared to $1.1 million for 2008. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from our natural gas processing and related NGL marketing business was $815.3 million for 2008 compared to $389.1 million for 2007. Equity NGL production increased to 108 MBPD during 2008 from 88 MBPD during 2007. The $426.2 million year-to-year increase in gross operating margin is largely due to contributions from our Meeker and Pioneer cryogenic natural gas processing facilities, which commenced commercial operations during October 2007 and February 2008, respectively. These facilities contributed $274.5 million of the year-to-year increase in gross operating margin and produced 49 MBPD of equity NGLs during 2008 compared to 23 MBPD during 2007.

Collectively, gross operating margin from the remainder of this business increased $151.7 million year-to-year primarily due improved results from our NGL marketing activities attributable to higher NGL sales margins and volumes in 2008 relative to 2007. Results for 2008 include $6.8 million of hurricane-related property damage repair expenses associated with our natural gas processing plants in southern Louisiana.

Gross operating margin from our NGL pipelines and related storage business was $369.2 million for 2008 compared to $302.2 million for 2007. Total NGL transportation volumes increased to 1,819 MBPD during 2008 from 1,666 MBPD during 2007. The $67.0 million year-to-year increase in gross operating margin from this business is primarily due to improved results from our Mid-America and Seminole Pipeline Systems and our Mont Belvieu storage complex. Gross operating margin from our Mid-America and Seminole Pipeline Systems increased $43.6 million year-to-year due to higher transportation volumes and an increase in the system-wide tariff. These pipeline systems contributed 116 MBPD of the year-to-year increase in NGL transportation volumes. Gross operating margin from our Mont Belvieu storage complex increased $15.5 million as a result of higher storage revenues during 2008 relative to 2007.

Gross operating margin from the remainder of our NGL pipeline and storage assets increased $7.9 million year-to-year attributable to (i) higher transportation volumes on our Dixie Pipeline System and our Lou-Tex NGL Pipeline and (ii) lower maintenance and pipeline integrity expenses on our Dixie Pipeline and South Louisiana Pipeline System. In general the improved results from our NGL pipeline and storage assets were partially offset by downtime and reduced volumes as a result of Hurricanes Gustav and Ike during 2008. Results for 2008 include $0.9 million of hurricane-related property damage repair expenses.

Gross operating margin from our NGL fractionation business was $104.8 million for 2008 compared to $88.4 million for 2007. Fractionation volumes increased from 394 MBPD during 2007 to 429 MBPD during 2008. Gross operating margin from our Hobbs fractionator increased $26.7 million year-to-year. Our Hobbs fractionator was placed into service during August 2007 and contributed a 41 MBPD year-to-year increase in NGL fractionation volumes. Collectively, gross operating margin from our other NGL fractionators decreased $10.3 million year-to-year primarily due to downtime and lower volumes at our Norco, South Texas and Baton Rouge fractionators and a combined $0.9 million of hurricane-related property damage repair expenses in 2008.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $411.3 million for 2008 compared to $335.7 million for 2007, a $75.6 million year-to-year increase. Our onshore natural gas transportation volumes were 7,477 BBtus/d during 2008 compared to 6,632 BBtus/d during 2007. Gross operating margin from our onshore natural gas pipeline and related natural gas marketing business increased $64.7 million year-to-year to $371.9 million for 2008 from $307.2 million for 2007. Collectively, gross operating margin from our natural gas pipelines increased $75.1 million year-to-year primarily due to (i) higher revenues from our San Juan Gathering System, (ii) higher transportation activity on our Texas Intrastate System, (iii) higher natural gas sales margins on our Acadian Gas System and (iv) increased equity earnings from our investment in Jonah. Results for 2008 include $1.3 million of hurricane-related property damage repair expenses attributable to Hurricanes Gustav and Ike. Gross operating margin from our natural gas marketing activities decreased $10.4 million year-to-year primarily due to non-cash mark-to-market related charges that are expected to be recouped in cash in future periods extending through 2009.

Our natural gas marketing business increased significantly during 2008. These marketing activities have four primary objectives: (i) to mitigate risk; (ii) maximize the use of our natural gas assets; (iii) to provide real-time market intelligence; and (iv) to link our noncontiguous natural gas assets together to enhance the profitability of such operations. To achieve these objectives, our natural gas marketing activities transact with various parties to provide transportation, balancing, storage, supply and sales services. The majority of our natural gas marketing activities are focused on the Gulf Coast and Rocky Mountain regions.

Our natural gas marketing business acquires a significant portion of the natural gas it sells from our processing plants and additional supplies from third parties at pipeline interconnects to facilitate incremental throughput on our natural gas transportation pipelines. This purchased gas is then sold to industrial consumers, utilities and power plants at prices that include a transportation fee. In addition, sales are made to third party marketing companies at industry hub locations in order to balance our supply/demand portfolio. Our purchase and sale transactions are typically based on published daily or monthly index prices. We utilize financial instruments to hedge various transactions within our natural gas marketing business.

We use third party transportation and storage capacity to link together our non-contiguous natural gas assets. Our natural gas marketing business contracts with third party transportation and storage providers to provide services on both a firm and interruptible basis. This strategy allows us to complement and strengthen our portfolio of natural gas assets.

Gross operating margin from our natural gas storage business was $39.4 million for 2008 compared to $28.4 million for 2007. The $11.0 million year-to-year increase in gross operating margin is primarily due to increased storage activity at our Petal natural gas storage facility and improved results at our Wilson facility. We placed additional natural gas storage caverns in operation during the third quarters of 2007 and 2008 at our Petal facility, which provided an additional 1.6 Bcf and 4.2 Bcf of subscribed capacity, respectively.

Offshore Pipelines & Services. Gross operating margin from this business segment was $188.1 million for 2008 compared to $171.6 million for 2007. The $16.5 million year-to-year increase in segment gross operating margin is primarily due to contributions from our Independence Hub and Trail project and improved results from our Cameron Highway Oil Pipeline. Results from this business segment for 2008 were negatively impacted by (i) downtime and $17.0 million of repair expenses associated with a leak on the Independence Trail pipeline and (ii) the effects of Hurricanes Gustav and Ike including downtime, reduced volumes and $37.2 million of property damage repair expenses. Results for 2008 include $0.2 million of proceeds from business interruption insurance claims compared to $3.4 million of proceeds during 2007. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance.

Gross operating margin from our offshore platform services business was $144.8 million for 2008 compared to $111.7 million for 2007, a $33.1 million year-to-year increase. Our Independence Hub platform, which was completed in March 2007, provided a $49.5 million year-to-year increase in gross operating margin. Gross operating margin increased year-to-year despite the platform being shut-in for 66 days during the second quarter of 2008 due to a leak on the Independence Trail export pipeline. While the Independence Hub platform did not earn volumetric fees during the period of suspended operations, the platform continued to earn its fixed demand revenues of approximately $4.6 million per month. Gross operating margin from the remainder of this business decreased $16.4 million year-to-year primarily due to the effects of Hurricanes Gustav and Ike and upstream supply disruptions. Results for our offshore platform services business include $5.0 million of hurricane-related property damage repair expenses in 2008. Our net platform natural gas processing volumes increased to 632 MMcf/d during 2008 compared to 494 MMcf/d during 2007.

Gross operating margin from our offshore crude oil pipeline business was $36.2 million for 2008 versus $21.1 million for 2007, a $15.1 million year-to-year increase. Gross operating margin increased $27.6 million year-to-year due to increased equity in earnings from Cameron Highway, which benefited from higher crude oil transportation volumes and lower interest expense in 2008 relative to 2007. Net to our ownership interest, crude oil transportation volumes on the Cameron Highway Oil Pipeline System were 80 MBPD in 2008 compared to 44 MBPD in 2007. Gross operating margin from the remainder of this business decreased $12.5 million year-to-year due to the effects of Hurricanes Gustav and Ike, which include (i) downtime resulting from damage sustained by our pipelines as well as downstream assets owned by third-party and (ii) reduced volumes available to our pipelines as a result of upstream supply disruptions. Results for our offshore crude oil pipeline business include $2.3 million of hurricane-related property damage repair expenses in 2008. Total offshore crude oil transportation volumes were 169 MBPD during 2008 versus 163 MBPD during 2007.

Gross operating margin from our offshore natural gas pipeline business was $6.9 million for 2008 compared to $35.4 million for 2007. Offshore natural gas transportation volumes were 1,408 BBtus/d during 2008 versus 1,641 BBtus/d during 2007. Gross operating margin from our Independence Trail pipeline, which first received production in July 2007, increased $28.4 million year-to-year on a 241 BBtus/d increase in transportation volumes. Collectively, gross operating margin from our other offshore natural gas pipelines decreased $56.9 million year-to-year primarily due to the effects of Hurricanes Gustav and Ike. Results for 2008 include $29.9 million of hurricane-related property damage repair expenses.

Petrochemical Services. Gross operating margin from this business segment was $167.6 million for 2008 compared to $172.3 million for 2007. Gross operating margin from our propylene fractionation and pipeline business was $83.1 million for 2008 compared to $62.6 million for 2007. The $20.5 million year-to-year increase in gross operating margin is largely due to higher propylene sales margins during 2008 relative to 2007. Results for our propylene fractionation and related pipeline business for 2008 include $0.8 million of hurricane-related property damage repair expenses.

Gross operating margin from our butane isomerization business was $95.9 million for 2008 compared to $91.4 million for 2007. The $4.5 million year-to-year increase in gross operating margin is primarily due to strong demand for high-purity isobutane and higher NGL prices, which resulted in higher by-product sales revenues during 2008 relative to 2007. Butane isomerization volumes decreased to 86 MBPD during 2008 compared to 90 MBPD during 2007 due to production interruptions resulting from Hurricane Ike and operational issues at our octane enhancement facility during the third quarter of 2008.

Gross operating margin from our octane enhancement business was a loss of $11.3 million for 2008 compared to $18.3 million of earnings for 2007. The $29.6 million year-to-year decrease in gross operating margin is primarily due to downtime, reduced volumes and higher operating expenses as a result of operational issues during the third quarter of 2008 and the effects of Hurricane Ike.

Comparison of 2007 with 2006

Revenues for 2007 were $16.95 billion compared to $13.99 billion for 2006. The $2.96 billion year-to-year increase in consolidated revenues is primarily due to higher sales volumes and energy commodity prices in 2007 relative to 2006. These factors accounted for a $2.94 billion increase in consolidated revenues associated with our marketing activities. Revenues from business interruption insurance proceeds totaled $36.1 million in 2007 compared to $63.9 million in 2006.

Operating costs and expenses were $16.01 billion for 2007 versus $13.09 billion for 2006. The $2.92 billion year-to-year increase in consolidated operating costs and expenses is primarily due to an increase in the cost of sales associated with our marketing activities. The cost of sales of our NGL, natural gas and petrochemical products increased $2.45 billion year-to-year as a result of an increase in volumes and higher energy commodity prices. Operating costs and expenses associated with our natural gas processing plants increased $185.7 million year-to-year as a result of higher energy commodity prices in 2007 relative to 2006. Operating costs and expenses associated with assets we constructed and placed into service or acquired since January 1, 2006 increased $188.1 million year-to-year.

General and administrative costs were $87.7 million for 2007 compared to $63.4 million for 2006. The $24.3 million year-to-year increase in general and administrative costs is primarily due to the recognition of a severance obligation during 2007 and an increase in legal fees.

Changes in our revenues and costs and expenses year-to-year are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.19 per gallon during 2007 versus $1.00 per gallon during 2006. The Henry Hub market price of natural gas averaged $6.86 per MMBtu during 2007 versus $7.24 per MMBtu during 2006. For additional historical energy commodity pricing information, see "Results of Operations – Selected Price and Volumetric Data" within this Item 7.

Equity in earnings from unconsolidated affiliates were $29.7 million for 2007 compared to $21.6 million for 2006. Equity in earnings from our investment in Jonah increased $9.1 million year-to-year due to an increase in our ownership interest in Jonah effective during the third quarter of 2007. Equity in earnings for 2007 include a non-cash impairment charge of $7.0 million associated with our investment in Nemo compared to a non-cash impairment charge of $7.4 million in 2006 related to our investment in Neptune Pipeline Company, L.L.C. ("Neptune"). Collectively, equity in earnings from our other unconsolidated affiliates decreased $1.4 million year-to-year primarily due to the sale of our investment in Coyote Gas Treating, LLC in August 2006.

Operating income for 2007 was $883.0 million compared to $860.1 million for 2006. Collectively, the aforementioned changes in revenues, costs and expenses and equity in earnings from unconsolidated affiliates contributed to the $22.9 million increase in operating income year-to-year.

Interest expense increased $73.7 million year-to-year primarily due to our issuance of junior subordinated notes in the second quarter of 2007 and third quarter of 2006 and the issuance of Senior Notes L in the third quarter of 2007. Our consolidated interest expense for 2007 includes $11.6 million associated with Duncan Energy Partners' credit facility. Our average debt principal outstanding was $6.18 billion in 2007 compared to $4.92 billion in 2006. Minority interest increased $21.6 million year-to-year attributable to the public unit holders of Duncan Energy Partners and third-party ownership interests in the Independence Hub platform.

As a result of items noted in the previous paragraphs, our consolidated net income decreased $67.5 million year-to-year to $533.7 million in 2007 compared to $601.2 million in 2006. Net income for 2006 includes a $1.5 million benefit relating to the cumulative effect of change in accounting principle. For additional information regarding the cumulative effect of change in accounting principle we recorded in 2006, see Note 8 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The following information highlights significant year-to-year variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $812.5 million for 2007 compared to $752.5 million for 2006. Gross operating margin for 2007 includes $32.7 million of proceeds from business interruption insurance claims compared to $40.4 million of proceeds during 2006. Strong demand for NGLs in 2007 compared to 2006 led to higher natural gas processing margins, increased volumes of natural gas processed under fee-based contracts and higher NGL throughput volumes at certain of our pipelines and fractionation facilities. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from NGL pipelines and storage was $302.2 million for 2007 compared to $265.7 million for 2006. Total NGL transportation volumes increased to 1,666 MBPD during 2007 from 1,577 MBPD during 2006. The $36.5 million year-to-year increase in gross operating margin is primarily due to higher pipeline transportation and NGL storage volumes at certain of our facilities and higher transportation fees charged to shippers on our Mid-America Pipeline System. Our DEP South Texas NGL Pipeline contributed $21.1 million of gross operating margin and 73 MBPD of NGL transportation volumes during 2007. The increase in gross operating margin year-to-year was partially offset by lower volumes and higher costs resulting from the November 2007 rupture of the Dixie Pipeline and a one-time benefit in 2006 for the settlement of a pipeline contamination incident.

Gross operating margin from our natural gas processing and related NGL marketing business was $389.1 million for 2007 compared to $359.7 million for 2006. The $29.4 million increase in gross operating margin year-to-year is largely due to improved results from our South Texas, Louisiana and Chaco natural gas processing facilities attributable to higher volumes and equity NGL sales revenues, all of which were partially offset by expenses associated with start-up delays at our Meeker and Pioneer natural gas processing plants. Fee-based processing volumes increased to 2.6 Bcf/d during 2007 from 2.2 Bcf/d during 2006. Equity NGL production increased to 88 MBPD during 2007 from 63 MBPD during 2006.

Gross operating margin from NGL fractionation was $88.4 million for 2007 compared to $86.8 million for 2006. Fractionation volumes increased from 312 MBPD during 2006 to 394 MBPD during 2007. The year-to-year increase in gross operating margin of $1.6 million is primarily due to higher volumes at our Norco NGL fractionator during 2007 relative to 2006. Our Norco NGL fractionator returned to normal operating rates in the second quarter of 2006 after suffering a reduction of fractionation volumes due to the effects of Hurricane Katrina. Gross operating margin attributable to our Hobbs NGL fractionator, which became operational in August 2007, was largely offset by start-up expenses. Fractionation volumes for 2007 include 36 MBPD from our Hobbs fractionator.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $335.7 million for 2007 compared to $333.4 million for 2006. Our total onshore natural gas transportation volumes were 6,632 BBtus/d for 2007 compared to 6,012 BBtus/d for 2006. Gross operating margin from our onshore natural gas pipeline business was $307.2 million for 2007 compared to $312.3 million for 2006. The $5.1 million year-to-year decrease in gross operating margin from this business is largely due to higher operating costs on our Acadian Gas System, Carlsbad Gathering System and our Texas Intrastate System.

Results from our onshore natural gas pipeline business for 2007 include $5.5 million of gross operating margin from our Piceance Creek Gathering System, which we acquired in December 2006. Equity in earnings from our investment in Jonah increased $9.1 million year-to-year. The Piceance Creek Gathering System and our net share of the gathering volumes on the Jonah Gathering System contributed 789 BBtus/d, collectively, of natural gas gathering volumes during 2007.

Gross operating margin from our natural gas storage business was $28.4 million for 2007 compared to $21.1 million for 2006. The $7.3 million year-to-year increase in gross operating margin is largely due to our Wilson natural gas storage facility attributable to lower repair costs in 2007 relative to 2006 and a 2006 loss on the sale of cushion gas. Our Wilson natural gas storage facility remained out of operation through 2007 due to ongoing repairs. Gross operating margin from our Petal facility includes an $8.4 million benefit in 2006 for a well measurement gain.

Offshore Pipelines & Services. Gross operating margin from this business segment was $171.6 million for 2007 compared to $103.4 million for 2006, a year-to-year increase of $68.2 million. Our Independence project contributed $85.0 million of gross operating margin during 2007 on average natural gas throughput of 423 BBtus/d. Segment gross operating margin for 2007 includes $3.4 million of proceeds from business interruption insurance claims compared to $23.5 million of proceeds in 2006. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from our offshore platform services business was $111.7 million for 2007 compared to $34.6 million for 2006. The $77.1 million year-to-year increase in gross operating margin is primarily due to our start up of the Independence Hub Platform in 2007, which contributed $63.6 million of gross operating margin in 2007. In addition, gross operating margin from the remainder of this business increased $13.5 million year-to-year primarily due to higher volumes during 2007 versus 2006. Our net platform natural gas processing volumes increased to 494 MMcf/d in 2007 from 159 MMcf/d in 2006.

Gross operating margin from our offshore natural gas pipeline business was $35.4 million for 2007 compared to $22.4 million for 2006. Offshore natural gas transportation volumes were 1,641 BBtus/d during 2007 versus 1,520 BBtus/d during 2006. Our Independence Trail Pipeline reported $21.4 million of gross operating margin and 423 BBtus/d of transportation volumes for 2007. Results from our Independence Trail Pipeline were partially offset by a decrease in volumes and revenues from our Viosca Knoll Gathering System and Constitution Gas Pipeline. Gross operating margin for 2007 includes a non-cash impairment charge of $7.0 million associated with our investment in Nemo compared to charge of $7.4 million in 2006 related to our investment in Neptune.

Gross operating margin from our offshore crude oil pipeline business was $21.1 million for 2007 versus $23.0 million for 2006. The $1.9 million year-to-year decrease in gross operating margin is primarily due to lower transportation volumes on our certain of our offshore crude oil pipelines and higher operating costs on our Poseidon Oil Pipeline System during 2007 relative to 2006. An increase in revenues year-to-year on our Cameron Highway Oil Pipeline System attributable to higher volumes was more than offset by a one-time expense of $8.8 million associated with the early termination of Cameron Highway's credit facility. Crude oil transportation volumes on our Cameron Highway Oil Pipeline System net to our ownership interest were 44 MBPD during 2007 compared to 32 MBPD during 2006. Total offshore crude oil transportation volumes were 163 MBPD during 2007 versus 153 MBPD during 2006.

Petrochemical Services. Gross operating margin from this business segment was $172.3 million for 2007 compared to $173.1 million for 2006. Gross operating margin from our butane isomerization business was $91.4 million for 2007 compared to $73.2 million for 2006. The $18.2 million year-to-year increase in gross operating margin is attributable to higher processing volumes and by-products sales revenues. Butane isomerization volumes were 90 MBPD for 2007 compared to 81 MBPD for 2006.

Gross operating margin from our propylene fractionation and pipeline activities was $62.6 million for 2007 versus $63.4 million for 2006. The $0.8 million year-to-year decrease in gross operating margin is primarily attributable to higher operating costs and expenses attributable to our propylene pipelines and our propylene storage and export facility. Petrochemical transportation volumes were 105 MBPD during 2007 compared to 97 MBPD during 2006. Gross operating margin from octane enhancement was $18.3 million for 2007 compared to $36.6 million for 2006. The year-to-year decrease of $18.3 million is primarily due to lower sales margins in 2007 relative to 2006. Octane enhancement production was 9 MBPD during 2007 and 2006.

Liquidity and Capital Resources

Our primary cash requirements, in addition to normal operating expenses and debt service, are for working capital, capital expenditures, business acquisitions and distributions to partners. We expect to fund our short-term needs for such items as operating expenses and sustaining capital expenditures with operating cash flows and short-term revolving credit arrangements. Capital expenditures for long-term needs resulting from business expansion projects and acquisitions are expected to be funded by a variety of sources (either separately or in combination) including operating cash flows, borrowings under credit facilities, the issuance of additional equity and debt securities and proceeds from divestitures of ownership interests in assets to affiliates or third parties. We expect to fund cash distributions to partners primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements.

At December 31, 2008, we had $35.4 million of unrestricted cash on hand and approximately $1.30 billion of available credit under EPO's Multi-Year Revolving Credit Facility and a new credit facility executed in November 2008. We had approximately $9.05 billion in principal outstanding under consolidated debt agreements at December 31, 2008. In total, our consolidated liquidity at December 31, 2008 was approximately $1.49 billion, which includes the available borrowing capacity of our consolidated subsidiaries such as Duncan Energy Partners.

Registration Statements

We may issue equity or debt securities to assist us in meeting our liquidity and capital spending requirements. Duncan Energy Partners may do likewise in meeting its liquidity and capital spending requirements. We have a universal shelf registration statement on file with the SEC that would allow us to issue an unlimited amount of debt and equity securities for general partnership purposes. In April 2008, EPO issued $1.10 billion in principal amount of fixed-rate, unsecured senior notes under this registration statement.

In December 2008, EPO also issued $500.0 million in principal amount of fixed-rate, unsecured senior notes. Net proceeds from these senior note offerings were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

In January 2009, we sold 10,590,000 common units (including an over-allotment of 990,000 common units) to the public at an offering price of $22.20 per unit. We used the net proceeds of $225.6 million from the offering to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility, which may be reborrowed to fund capital expenditures and other growth projects, and for general partnership purposes.

During 2003, we instituted a distribution reinvestment plan ("DRIP"). We have a registration statement on file with the SEC authorizing the issuance of up to 25,000,000 common units in connection with the DRIP. The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional common units of our partnership. During the year ended December 31, 2008, we issued 5,368,310 common units in connection with our DRIP, which generated proceeds of $134.7 million from plan participants. In November 2008, affiliates of EPCO reinvested $67.0 million in connection with the DRIP.

We also have a registration statement on file related to our employee unit purchase plan, under which we can issue up to 1,200,000 common units. Under this plan, employees of EPCO can purchase our common units at a 10.0% discount through payroll deductions. During the year ended December 31, 2008, we issued 155,636 common units to employees under this plan, which generated proceeds of $4.5 million.

In March 2008, Duncan Energy Partners filed a universal shelf registration statement with the SEC that authorized its issuance of up to $1.00 billion in debt and equity securities. In December 2008, Duncan Energy Partners issued $0.5 million in equity securities under its registration statement.

For information regarding our public debt obligations or partnership equity, see Notes 14 and 15, respectively, of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Letter of Credit Facility

In October 2008, EPO entered into a $100.0 million letter of credit facility. EPO issued a $70.0 million letter of credit under this new facility, which remained outstanding at December 31, 2008. This letter of credit facility does not reduce the amount available under our Multi-Year Revolving Credit Facility.

Credit Ratings of EPO

At March 2, 2009, the investment-grade credit ratings of EPO's senior unsecured debt securities remain unchanged from 2008 at Baa3 by Moody's Investor Services; BBB- by Fitch Ratings; and BBB- by Standard and Poor's. Such ratings reflect only the view of a rating agency and should not be interpreted as a recommendation to buy, sell or hold any security. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it determines that the circumstances warrant such a change and should be evaluated independently of any other rating.

Based on the characteristics of the $1.25 billion of fixed/floating unsecured junior subordinated notes that EPO issued in 2006 and 2007, the rating agencies assigned partial equity treatment to the notes. Moody's Investor Services and Standard and Poor's each assigned 50.0% equity treatment and Fitch Ratings assigned 75.0% equity treatment.

In connection with the construction of our Pascagoula, Mississippi natural gas processing plant, EPO entered into a $54.0 million, ten-year, fixed-rate loan with the Mississippi Business Finance Corporation ("MBFC"). The indenture agreement for this loan contains an acceleration clause whereby if EPO's credit rating by Moody's Investor Services declines below Baa3 in combination with our credit rating at Standard & Poor's declining below BBB-, the $54.0 million principal balance of this loan, together with all accrued and unpaid interest would become immediately due and payable 120 days following such event. If such an event occurred, EPO would have to either redeem the Pascagoula MBFC Loan or provide an alternative credit agreement to support its obligation under this loan.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our cash flows from operating, investing and financing activities for the periods indicated (dollars in millions). For information regarding the individual components of our cash flow amounts, see the Statements of Consolidated Cash Flows.

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Net cash flows provided by operating activities	$ 1,237.1	$ 1,590.9	$ 1,175.1
Cash used in investing activities	2,411.9	2,553.6	1,689.3
Cash provided by financing activities	1,171.0	979.4	495.0

Net cash flows provided by operating activities are largely dependent on earnings from our business activities. As a result, these cash flows are exposed to certain risks. We operate predominantly in the midstream energy industry. We provide services for producers and consumers of natural gas, NGLs, crude oil and certain petrochemicals. The products that we process, sell or transport are principally used as fuel for residential, agricultural and commercial heating; feedstock in petrochemical manufacturing; and in the production of motor gasoline. Reduced demand for our services or products by industrial customers, whether because of a decline in general economic conditions, reduced demand for the end products made with our products, or increased competition from other service providers or producers due to pricing differences or other reasons, could have a negative impact on our earnings and operating cash flows. For a more complete discussion of these and other risk factors pertinent to our business, see "Risk Factors" under Item 1A of this annual report.

Our Statements of Consolidated Cash Flows are prepared using the indirect method. The indirect method derives net cash flows from operating activities by adjusting net income to remove (i) the effects of all deferrals of past operating cash receipts and payments, such as changes during the period in inventory, deferred income and similar transactions, (ii) the effects of all accruals of expected future operating cash receipts and cash payments, such as changes during the period in receivables and payables, (iii) other non-cash amounts such as depreciation, amortization, operating lease expense paid by EPCO, changes in the fair market value of financial instruments and equity in earnings from unconsolidated affiliates (net cash flows provided by operating activities reflect the actual cash distributions we receive from such investees), and (iv) the effects of all items classified as investing or financing cash flows, such as proceeds from asset sales and related transactions or extinguishment of debt.

In general, the net effect of changes in operating accounts results from the timing of cash receipts from sales and cash payments for purchases and other expenses during each period. Increases or decreases in inventory are influenced by the quantity of products held in connection with our marketing activities and changes in energy commodity prices.

Cash used in investing activities primarily represents expenditures for additions to property, plant and equipment, business combinations and investments in unconsolidated affiliates. Cash provided by financing activities generally consists of borrowings and repayments of debt, distributions to partners and proceeds from the issuance of equity securities. Amounts presented in our Statements of Consolidated Cash Flows for borrowings and repayments under debt agreements are influenced by the magnitude of cash receipts and payments under our revolving credit facilities.

The following information highlights the significant year-to-year variances in our cash flow amounts:

Comparison of 2008 with 2007

Operating Activities. Net cash flows provided by operating activities were $1.24 billion for 2008 compared to $1.59 billion for 2007. The $353.9 million decrease in net cash flows provided by operating activities was primarily due to the following:

- Net cash flows from consolidated operations (excluding distributions received from unconsolidated affiliates and cash payments for interest) decreased $262.6 million year-to-year. Although our gross operating margin increased year-to-year (see "Results of Operations" within this Item 7), the reduction in operating cash flow is generally due to the timing of related cash receipts and disbursements. The $262.6 million total year-to-year decrease also reflects a $127.3 million decrease in cash proceeds we received from insurance claims related to certain named storms. For information regarding proceeds from business interruption and property damage claims, see Note 21 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

- Cash distributions received from unconsolidated affiliates increased $25.0 million year-to-year primarily due to increased distributions from Jonah and Cameron Highway.

- Cash payments for interest increased $116.3 million year-to-year primarily due to increased borrowings to finance our capital spending program.

Investing Activities. Cash used in investing activities was $2.41 billion for 2008 compared to $2.55 billion for 2007. The $141.7 million decrease in cash used for investing activities was primarily due to the following:

- Capital spending for property, plant and equipment, net of contributions in aid of construction costs, decreased $174.6 million year-to-year. For additional information related to our capital spending program, see "Capital Spending" included within this Item 7.

- Cash outlays for investments in and advances to unconsolidated affiliates decreased by $208.9 million year-to-year. Expenditures for 2007 include the $216.5 million we contributed to Cameron Highway during the second quarter of 2007. Cameron Highway used these funds, along with an equal contribution from our 50.0% joint venture partner in Cameron Highway, to repay approximately $430.0 million of its outstanding debt. In addition, cash contributions to Jonah decreased $83.0 million year-to-year as a result of the completion of an expansion project in June 2008. Expenditures for 2008 include $22.5 million in contributions to White River Hub, LLC, $36.0 million to acquire a 49.0% interest in Skelly-Belvieu Pipeline Company, L.L.C., and $35.9 million in contributions to the Texas Offshore Port System joint venture.

- An $85.4 million increase in restricted cash (a cash outflow) due to margin requirements primarily due to our hedging activities. See Item 7A of this annual report for information regarding our interest rate and commodity risk hedging portfolios.

- Cash used for business combinations increased $166.4 million year-to-year primarily due to the acquisition of a 100.0% membership interest in Great Divide Gathering LLC for $125.2 million, the acquisition of the remaining interests in Dixie for $57.1 million and the acquisition of additional interests in Tri-States NGL Pipeline, L.L.C ("Tri-States") for $18.7 million.

Financing Activities. Cash provided by financing activities was $1.17 billion for 2008 compared to $979.4 million for 2007. This $191.6 million increase in cash provided by financing activities was primarily due to the following:

- Net borrowings under our consolidated debt agreements increased $588.9 million year-to-year. In April 2008, EPO sold $400.0 million in principal amount of fixed-rate unsecured senior notes ("Senior Notes M") and $700.0 million in principal amount of fixed-rate unsecured senior notes ("Senior Notes N"). In November 2008, EPO executed a Japanese yen term loan agreement in the amount of 20.7 billion yen (approximately $217.6 million U.S. dollar equivalent). In December 2008, EPO sold $500.0 million in principal amount of fixed-rate unsecured senior notes ("Senior Notes O"). We used the proceeds from these borrowings primarily to repay amounts borrowed under our Multi-Year Revolving Credit Facility and, to a lesser extent, for general partnership purposes. For information regarding our consolidated debt obligations, see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

- Net proceeds from the issuance of our common units increased $73.6 million year-to-year due to increased participation in our DRIP.

- Contributions from minority interests decreased $302.9 million year-to-year primarily due to the initial public offering of Duncan Energy Partners in February 2007, which generated proceeds of $290.5 million.

- Cash distributions to our partners and minority interests increased $103.2 million year-to-year primarily due to increases in our common units outstanding and quarterly distribution rates, increases in the quarterly distribution rates of Duncan Energy Partners and distributions paid to Independence Hub's joint venture partner.

- The early termination and settlement of interest rate hedging financial instruments during 2008 resulted in net cash payments of $14.4 million compared to net cash receipts of $48.9 million during the same period in 2007, which resulted in a $63.3 million decrease in financing cash flows between years.

Comparison of 2007 with 2006

Operating activities. Net cash flows provided by operating activities was $1.59 billion for 2007 compared to $1.18 billion for 2006. The $415.9 million year-to-year increase in net cash flows provided by operating activities was primarily due to the following:

- Our net cash flows from consolidated businesses (excluding distributions received from unconsolidated affiliates and cash payments for interest and taxes) increased $436.8 million year-to-year. The improvement in cash flow is generally due to increased gross operating margin and the timing of related cash collections and disbursements between periods. The $436.8 million total year-to-year increase also reflects a $42.1 million increase in cash proceeds we received from insurance claims related to certain named storms.

- Cash distributions received from unconsolidated affiliates increased $30.6 million year-to-year primarily due to improved earnings from our Gulf of Mexico investments, which were negatively impacted during 2006 as a result of the lingering effects of Hurricanes Katrina and Rita.

- Cash payments for interest increased $56.2 million year-to-year primarily due to increased borrowings to finance our capital spending program. Our average debt balance for 2007 was $6.26 billion compared to $4.93 billion for 2006.

- Cash payments for taxes decreased $4.7 million year-to-year.

Investing activities. Cash used in investing activities was $2.55 billion for 2007 compared to $1.69 billion for 2006. The $864.3 million year-to-year increase in cash used for investing activities was primarily due to the following:

- An $847.7 million increase in capital spending for property, plant and equipment (net of contributions in aid of construction costs) and a $194.6 million increase in investments in unconsolidated affiliates, partially offset by a $240.7 million decrease in cash outlays for business combinations.

- We contributed $216.5 million to Cameron Highway during the second quarter of 2007. Cameron Highway used these funds, along with an equal contribution from our 50.0% joint venture partner in Cameron Highway, to repay approximately $430.0 million of its outstanding debt.

- During 2006, we paid $100.0 million for Piceance Creek Pipeline, LLC and $145.2 million for the Encinal acquisition. Our spending for business combinations during 2007 was limited and primarily due to the $35.0 million we paid to acquire the South Monco pipeline business.

- Restricted cash increased $38.6 million (a cash outflow) year-to-year.

Financing activities. Cash provided by financing activities was $979.4 million for 2007 versus $495.0 million for 2006. The $484.4 million year-to-year increase in cash provided by financing activities was primarily due to the following:

- Net borrowings under our consolidated debt agreements increased $1.10 billion year-to-year. In May 2007, EPO sold $700.0 million in principal amount of fixed/floating unsecured junior subordinated notes (Junior Notes B"). In September 2007, EPO sold $800.0 million in principal amount of fixed-rate unsecured senior notes ("Senior Notes L") and in October 2007, EPO repaid $500.0 million in principal amount of fixed-rate unsecured senior notes ("Senior Notes E").

- Net proceeds from the issuance of our common units decreased $788.0 million year-to-year. We completed underwritten equity offerings in March and September of 2006 that generated net proceeds of $750.8 million reflecting the sale of 31,050,000 common units.

- Contributions from minority interests increased $275.4 million year-to-year primarily due to the initial public offering of Duncan Energy Partners in February 2007, which generated net proceeds of $290.5 million from the sale of 14,950,000 of its common units. See "Other Items – Duncan Energy Partners Transactions" within this Item 7 for additional information regarding Duncan Energy Partners.

- Cash distributions to our partners and minority interests increased $137.9 million year-to-year primarily due to an increase in common units outstanding and our quarterly cash distribution rates.

- We received $48.9 million from the settlement of treasury lock financial instruments during 2007 related to our interest rate risk hedging activities.

Capital Spending

An integral part of our business strategy involves expansion through business combinations, growth capital projects and investments in joint ventures. We believe that we are positioned to continue to grow our system of assets through the construction of new facilities and to capitalize on expected increases in natural gas and/or crude oil production from resource basins such as the Piceance Basin of western Colorado, the Greater Green River Basin in Wyoming, Barnett Shale in North Texas, and the deepwater Gulf of Mexico.

Management continues to analyze potential acquisitions, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions. In past years, major oil and gas companies have sold non-strategic assets in the midstream energy sector in which we operate. We forecast that this trend will continue, and expect independent oil and natural gas companies to consider similar divestitures.

The following table summarizes our capital spending by activity for the periods indicated (dollars in thousands):

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Capital spending for business combinations:			
Great Divide Gathering System acquisition	$ 125,175	$ --	$ --
Encinal acquisition, excluding non-cash consideration (1)	--	114	145,197
Piceance Basin Gathering System acquisition	--	368	100,000
South Monco Pipeline System acquisition	1	35,000	--
Canadian Enterprise Gas Products, Ltd. acquisition	--	--	17,690
Additional ownership interests in Dixie	57,089	311	12,913
Additional ownership interests in Belle Rose NGL Pipeline, LLC	1,200	--	--
Additional ownership interests in Tri-States	18,695	--	--
Other business combinations	--	--	700
Total	202,160	35,793	276,500
Capital spending for property, plant and equipment, net: (2)			
Growth capital projects (3)	1,773,000	1,986,157	1,148,123
Sustaining capital projects (4)	180,676	142,096	132,455
Total	1,953,676	2,128,253	1,280,578
Capital spending for intangible assets:			
Acquisition of intangible assets (5)	5,126	11,232	--
Capital spending attributable to unconsolidated affiliates:			
Investments in unconsolidated affiliates (6)	129,816	332,909	138,266
Total capital spending	$ 2,290,778	$ 2,508,187	$ 1,695,344

(1) Excludes $181.1 million of non-cash consideration paid to the seller in the form of 7,115,844 of our common units. See Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding our business combinations.

(2) On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with projects related to pipeline construction and production well tie-ins. Contributions in aid of construction costs were $25.8 million, $57.5 million and $60.5 million for the years ended December 31, 2008, 2007 and 2006, respectively.

(3) Growth capital projects either result in additional revenue streams from existing assets or expand our asset base through construction of new facilities that will generate additional revenue streams.

(4) Sustaining capital expenditures are capital expenditures (as defined by GAAP) resulting from improvements to and major renewals of existing assets. Such expenditures serve to maintain existing operations but do not generate additional revenues.

(5) Amount for 2008 represents the acquisition of permits for our Mont Belvieu storage facility. Amount for 2007 represents the acquisition of nitric oxide credits at our Morgan's Point Facility.

(6) Fiscal 2007 includes $216.5 million in cash contributions to Cameron Highway to fund our share of the repayment of its debt obligations.

Based on information currently available, we estimate our consolidated capital spending for 2009 will approximate $1.00 billion, which includes estimated expenditures of $820.0 million for growth capital projects and acquisitions and $180.0 million for sustaining capital expenditures.

Our forecast of consolidated capital expenditures is based on our current announced strategic operating and growth plans, which are dependent upon our ability to generate the required funds from either operating cash flows or from other means, including borrowings under debt agreements, issuance of equity, and potential divestitures of certain assets to third and/or related parties. Our forecast of capital expenditures may change due to factors beyond our control, such as weather related issues, changes in supplier prices or adverse economic conditions. Furthermore, our forecast may change as a result of decisions made by management at a later date, which may include acquisitions or decisions to take on additional partners.

Our success in raising capital, including the formation of joint ventures to share costs and risks, continues to be a principal factor that determines how much capital we can invest. We believe our access to capital resources is sufficient to meet the demands of our current and future operating growth needs, and although we currently intend to make the forecasted expenditures discussed above, we may adjust the timing and amounts of projected expenditures in response to changes in capital markets.

At December 31, 2008, we had approximately $521.3 million in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These commitments primarily relate to construction of our Barnett Shale natural gas pipeline projects and Meeker natural gas processing plant expansion.

Significant Ongoing Growth Capital Projects

The following table summarizes information regarding certain ongoing significant announced growth capital projects (dollars in millions). Actual costs noted for each project reflects our share of cash expenditures as of December 31, 2008, excluding capitalized interest. The current forecast amount noted for each project also reflects our share of project expenditures, excluding estimated capitalized interest.

Project Name	Estimated Date of Completion	Actual Costs	Current Forecast Total Cost
Sherman Extension Pipeline (Barnett Shale)	2009	$ 457.0	$ 489.2
Shenzi Oil Pipeline	2009	135.8	153.5
Marathon Piceance Basin pipeline projects	2009	36.6	151.3
Trinity River Basin Extension	2009	16.4	232.6
Expansion of Wilson natural gas storage facility	2010	51.1	119.6
Texas Offshore Port System	To be determined	30.0	600.0

Sherman Extension Pipeline (Barnett Shale). In November 2006, we announced an expansion of our Texas Intrastate System with the construction of the Sherman Extension that will transport up to 1.1 Bcf/d of natural gas from the growing Barnett Shale area of North Texas. The Sherman Extension is supported by long-term contracts with Devon Energy Corporation, the largest producer in the Barnett Shale area, and significant indications of interest from leading producers and gatherers in the Fort Worth basin, as well as other shippers on our Texas Intrastate Pipeline system. At its terminus, the new pipeline system will make deliveries into Boardwalk Pipeline Partners L.P.'s Gulf Crossing Expansion Project, which will provide export capacity for Barnett Shale natural gas production to multiple delivery points in Louisiana, Mississippi and Alabama that offer access to attractive markets in the Northeast and Southeast United States. In addition, the Sherman Extension will provide natural gas producers in East Texas and the Waha area of West Texas with access to these higher value markets through our Texas Intrastate Pipeline system. The Sherman Extension will originate near Morgan Mill, Texas and extend through the center of the current Barnett Shale development area to Sherman, Texas. In 2008, we placed into service portions of the Sherman Extension. The Sherman Extension is scheduled for final completion in March 2009.

The Barnett Shale is considered to be one of the largest unconventional natural gas resource plays in North America, covering approximately 14 counties and over seven million acres in the Fort Worth basin in North Texas. Current natural gas production is estimated at 3.4 Bcf/d from approximately 7,800 wells. Approximately 190 rigs are currently estimated to be working to develop Barnett Shale acreage in the region. According to the United States Geological Survey, the Barnett Shale has the resource potential of approximately 26 trillion cubic feet of natural gas.

Shenzi Oil Pipeline. In October 2006, we announced the execution of definitive agreements with producers to construct, own and operate an oil export pipeline that will provide firm gathering services from the BHP Billiton Plc-operated Shenzi production field located in the South Green Canyon area of the central Gulf of Mexico. The Shenzi oil export pipeline will originate at the Shenzi Field, located in 4,300 feet of water at Green Canyon Block 653, approximately 120 miles off the coast of Louisiana. The 83-mile, 20-inch diameter pipeline will have the capacity to transport up to 230 MBPD of crude oil and will connect the Shenzi Field to our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System at our Ship Shoal 332B junction platform. We own a 50.0% interest in the Cameron Highway Oil Pipeline and a 36.0% interest in the Poseidon Oil Pipeline System and operate both pipelines. The Shenzi oil export pipeline will connect to a platform being constructed by BHP Billiton Plc to develop the Shenzi Field, which is expected to commence operations during the second quarter of 2009.

Marathon Piceance Basin pipeline projects. In December 2006, we entered into a long-term contract with Marathon Oil Company ("Marathon") to provide a range of midstream energy services, including natural gas gathering, compression, treating and processing, for Marathon's natural gas production in the Piceance Basin of northwest Colorado. Under the terms of the contract, we are constructing 50 miles of gathering lines and related assets to connect Marathon's multi-well drilling sites, production from which is expected to peak at approximately 180 MMcf/d, to our Piceance Creek Gathering System. From there the natural gas will be delivered to our Meeker natural gas processing facility.

Trinity River Basin Extension. In August 2008, we announced the development of a new 40-mile supply lateral that will extend from the Trinity River Basin north of Arlington, Texas to an interconnect with the Sherman Extension pipeline near Justin, Texas to accommodate growing natural gas production from the Barnett Shale. This new pipeline will consist of 30-inch and 36-inch diameter pipeline designed to provide up to 1.0 Bcf/d of natural gas takeaway capacity for producers in Tarrant and Denton counties. This new pipeline will also have a lateral to provide transportation services for natural gas produced from the Newark East field in Wise County. These new pipeline laterals are anchored by long-term agreements with major producers and are expected to be in-service by year end 2009.

Expansion of Wilson natural gas storage facility. We are developing a new natural gas storage cavern located on the Boling Salt Dome near Boling, Texas. The cavern is designed to store approximately 7.9 Bcf of natural gas, of which approximately 5.0 Bcf will be working gas capacity and 2.9 Bcf will be the base gas requirements needed to support minimum pressures. This expansion project was approved by the Texas Railroad Commission and is projected to commence operations in 2010. We expect to secure binding precedent agreements on all capacity before the cavern commences operations.

Texas Offshore Port System (TOPS and PACE). In August 2008, we, together with TEPPCO and Oiltanking, announced the formation of a joint venture to design, construct, operate and own a Texas offshore crude oil port and a related onshore pipeline and storage system that would facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. We, TEPPCO and Oiltanking each own, through our respective subsidiaries, a one-third interest in the joint venture. For additional information regarding this joint venture and its capital projects, see "Recent Developments – Texas Offshore Port System" within this Item 7.

Pipeline Integrity Costs

Our NGL, petrochemical and natural gas pipelines are subject to pipeline safety programs administered by the U.S. Department of Transportation, through its Office of Pipeline Safety. This federal agency has issued safety regulations containing requirements for the development of integrity management programs for hazardous liquid pipelines (which include NGL and petrochemical pipelines) and natural gas pipelines. In general, these regulations require companies to assess the condition of their pipelines in certain high consequence areas (as defined by the regulation) and to perform any necessary repairs.

In April 2002, a subsidiary of ours acquired several midstream energy assets located in Texas and New Mexico from El Paso Corporation ("El Paso"). These assets included the Texas Intrastate System and the Carlsbad Gathering Systems. With respect to such assets, El Paso agreed to indemnify our subsidiary for any pipeline integrity costs it incurred (whether paid or payable) for five years following the acquisition date. The indemnity provisions did not take effect until such costs exceeded $3.3 million annually; however, the amount reimbursable by El Paso was capped at $50.2 million in the aggregate. In 2007 and 2006, we recovered $31.1 million and $13.7 million, respectively from El Paso related to our 2006 and 2005 expenditures. During 2007, we received a final amount of $5.4 million from El Paso related to this indemnity.

The following table summarizes our pipeline integrity costs, net of indemnity payments from El Paso, for the periods indicated (dollars in thousands):

	For the Year Ended December 31,		
	2008	2007	2006
Expensed	$ 48,664	$ 43,499	$ 26,397
Capitalized	63,976	52,420	38,180
Total	$ 112,640	$ 95,919	$ 64,577

We expect our cash outlay for the pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $107.0 million in 2009.

Critical Accounting Policies and Estimates

In our financial reporting process, we employ methods, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of our financial statements. These methods, estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Investors should be aware that actual results could differ from these estimates if the underlying assumptions prove to be incorrect. The following describes the estimation risk currently underlying our most significant financial statement items:

Depreciation methods and estimated useful lives of property, plant and equipment

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of the assets. Our estimate of depreciation incorporates assumptions regarding the useful economic lives and residual values of our assets. At the time we place our assets in-service, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation amounts prospectively.

Examples of such circumstances include:

- changes in laws and regulations that limit the estimated economic life of an asset;
- changes in technology that render an asset obsolete;
- changes in expected salvage values; or
- changes in the forecast life of applicable resource basins, if any.

At December 31, 2008 and 2007, the net book value of our property, plant and equipment was $13.15 billion and $11.59 billion, respectively. We recorded $466.1 million, $414.9 million, and $350.8 million in depreciation expense for the years ended December 31, 2008, 2007 and 2006, respectively.

For additional information regarding our property, plant and equipment, see Notes 2 and 10 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Measuring recoverability of long-lived assets and equity method investments

In general, long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Examples of such events or changes might be production declines that are not replaced by new discoveries or long-term decreases in the demand or price of natural gas, oil or NGLs. Long-lived assets with recorded values that are not expected to be recovered through expected future cash flows are written-down to their estimated fair values. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of undiscounted estimated cash flows expected to result from the use and eventual disposition of the existing asset. Our estimates of such undiscounted cash flows are based on a number of assumptions including anticipated operating margins and volumes; estimated useful life of the asset or asset group; and estimated salvage values. An impairment charge would be recorded for the excess of a long-lived asset's carrying value over its estimated fair value, which is based on a series of assumptions similar to those used to derive undiscounted cash flows. Those assumptions also include usage of probabilities for a range of possible outcomes, market values and replacement cost estimates.

An equity method investment is evaluated for impairment whenever events or changes in circumstances indicate that there is a possible loss in value of the investment other than a temporary decline. Examples of such events include sustained operating losses of the investee or long-term negative changes in the investee's industry. Equity method investments with carrying values that are not expected to be recovered through expected future cash flows are written down to their estimated fair values. The carrying value of an equity method investment is not recoverable if it exceeds the sum of discounted estimated cash flows expected to be derived from the investment. This estimate of discounted cash flows is based on a number of assumptions including discount rates; probabilities assigned to different cash flow scenarios; anticipated margins and volumes and estimated useful life of the investment. A significant change in these underlying assumptions could result in our recording an impairment charge.

We recognized a non-cash asset impairment charge related to property, plant and equipment of $0.1 million in 2006, which is reflected as a component of operating costs and expenses. No such asset impairment charges were recorded in 2008 or 2007.

During 2007, we evaluated our equity method investment in Nemo for impairment. As a result of this evaluation, we recorded a $7.0 million non-cash impairment charge that is a component of equity in earnings from unconsolidated affiliates for the year ended December 31, 2007. Similarly, during the year ended December 31, 2006, we evaluated our equity method investment in Neptune for impairment and recorded a $7.4 million non-cash impairment charge. During 2008 there were no such impairment charges.

For additional information regarding impairment charges associated with our long-lived assets and equity method investments, see Notes 2 and 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Amortization methods and estimated useful lives of qualifying intangible assets

The specific, identifiable intangible assets of a business enterprise depend largely upon the nature of its operations. Potential intangible assets include intellectual property, such as technology, patents, trademarks and trade names, customer contracts and relationships, and non-compete agreements, as well as other intangible assets. The method used to value each intangible asset will vary depending upon the nature of the asset, the business in which it is utilized, and the economic returns it is generating or is expected to generate.

Our customer relationship intangible assets primarily represent the customer base we acquired in connection with business combinations and asset purchases. The value we assigned to these customer relationships is being amortized to earnings using methods that closely resemble the pattern in which the economic benefits of the underlying oil and natural gas resource bases from which the customers produce are estimated to be consumed or otherwise used. Our estimate of the useful life of each resource base is based on a number of factors, including reserve estimates, the economic viability of production and exploration activities and other industry factors.

Our contract-based intangible assets represent the rights we own arising from discrete contractual agreements, such as the long-term rights we possess under the Shell natural gas processing agreement. A contract-based intangible asset with a finite life is amortized over its estimated useful life (or term), which is the period over which the asset is expected to contribute directly or indirectly to the cash flows of an entity. Our estimates of useful life are based on a number of factors, including:

- the expected useful life of the related tangible assets (e.g., fractionation facility, pipeline, etc.);

- any legal or regulatory developments that would impact such contractual rights; and

- any contractual provisions that enable us to renew or extend such agreements.

If our underlying assumptions regarding the estimated useful life of an intangible asset change, then the amortization period for such asset would be adjusted accordingly. Additionally, if we determine that an intangible asset's unamortized cost may not be recoverable due to impairment; we may be required to reduce the carrying value and the subsequent useful life of the asset. Any such write-down of the value and unfavorable change in the useful life of an intangible asset would increase operating costs and expenses at that time.

At December 31, 2008 and 2007, the carrying value of our intangible asset portfolio was $855.4 million and $917.0 million, respectively. We recorded $88.4 million, $89.7 million, and $88.8 million in amortization expense associated with our intangible assets for the years ended December 31, 2008, 2007 and 2006, respectively.

For additional information regarding our intangible assets, see Notes 2 and 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Methods we employ to measure the fair value of goodwill

Goodwill represents the excess of the purchase prices we paid for certain businesses over their respective fair values. We do not amortize goodwill; however, we test our goodwill (at the reporting unit level) for impairment during the second quarter of each fiscal year, and more frequently, if circumstances indicate it is more likely than not that the fair value of goodwill is below its carrying amount. Our goodwill testing involves the determination of a reporting unit's fair value, which is predicated on our assumptions regarding the future economic prospects of the reporting unit.

Such assumptions include:

- discrete financial forecasts for the assets contained within the reporting unit, which rely on management's estimates of operating margins and transportation volumes;

- long-term growth rates for cash flows beyond the discrete forecast period; and

- appropriate discount rates.

If the fair value of the reporting unit (including its inherent goodwill) is less than its carrying value, a charge to earnings is required to reduce the carrying value of goodwill to its implied fair value. At December 31, 2008 and 2007, the carrying value of our goodwill was $706.9 million and $591.7 million, respectively. We did not record any goodwill impairment charges during the periods presented.

For additional information regarding our goodwill, see Notes 2 and 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our revenue recognition policies and use of estimates for revenues and expenses

In general, we recognize revenue from our customers when all of the following criteria are met:

- persuasive evidence of an exchange arrangement exists;

- delivery has occurred or services have been rendered;

- the buyer's price is fixed or determinable; and

- collectability is reasonably assured.

We record revenue when sales contracts are settled (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed). We record any necessary allowance for doubtful accounts as required by our established policy.

Our use of certain estimates for revenues and expenses has increased as a result of SEC regulations that require us to submit financial information on accelerated time frames. Such estimates are necessary due to the timing to compile actual billing information and receiving third-party data needed to record transactions for financial reporting purposes. One example of such use of estimates is the accrual of an estimate of processing plant revenue and the cost of natural gas for a given month (prior to receiving actual customer and vendor-related plant operating information for the subject period). These estimates reverse in the following month and are offset by the corresponding actual customer billing and vendor-invoiced amounts. Accordingly, we include one month of certain estimated data in our results of operations. Such estimates are generally based on actual volume and price data through the first part of the month and estimated for the remainder of the month, adjusted accordingly for any known or expected changes in volumes or rates through the end of the month.

If the basis of our estimates proves to be substantially incorrect, it could result in material adjustments in results of operations between periods. On an ongoing basis, we review our estimates based on currently available information. Changes in facts and circumstances may result in revised estimates and could affect our reported financial statements and accompanying notes.

Reserves for environmental matters

Each of our business segments is subject to federal, state and local laws and regulations governing environmental quality and pollution control. Such laws and regulations may, in certain instances, require us to remediate current or former operating sites where specified substances have been released or disposed of. We accrue reserves for environmental matters when our assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. Our assessments are based on studies, as well as site surveys, to determine the extent of any environmental damage and the necessary requirements to remediate this damage. Future environmental developments, such as increasingly strict environmental laws and additional claims for damages to property, employees and other persons resulting from current or past operations, could result in substantial additional costs beyond our current reserves. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. At December 31, 2008, none of our estimated environmental remediation liabilities are discounted to present value since the ultimate amount and timing of cash payments for such liabilities are not readily determinable.

At December 31, 2008 and 2007, we had a liability for environmental remediation of $15.4 million and $26.5 million, respectively, which was derived from a range of reasonable estimates based upon studies and site surveys. We follow the provisions of American Institute of Certified Public Accountants Statement of Position 96-1, which provides key guidance on recognition, measurement and disclosure of remediation liabilities. We have recorded our best estimate of the cost of remediation activities.See Item 3 of this annual report for recent developments regarding environmental matters.

Natural gas imbalances

In the pipeline transportation business, imbalances frequently result from differences in natural gas volumes received from and delivered to our customers. Such differences occur when a customer delivers more or less gas into our pipelines than is physically redelivered back to them during a particular time period. The vast majority of our settlements are through in-kind arrangements whereby incremental volumes are delivered to a customer (in the case of an imbalance payable) or received from a customer (in the case of an imbalance receivable). Such in-kind deliveries are on-going and take place over several months. In some cases, settlements of imbalances accumulated over a period of time are ultimately cashed out and are generally negotiated at values which approximate average market prices over a period of time. As a result, for gas imbalances that are ultimately settled over future periods, we estimate the value of such current assets and liabilities using average market prices, which is representative of the estimated value of the imbalances upon final settlement. Changes in natural gas prices may impact our estimates.

At December 31, 2008 and 2007, our imbalance receivables, net of allowance for doubtful accounts, were $48.4 million and $60.9 million, respectively, and are reflected as a component of "Accounts and notes receivable – trade" on our Consolidated Balance Sheets included in this annual report. At December 31, 2008 and 2007, our imbalance payables were $40.7 million and $38.3 million, respectively, and are reflected as a component of "Accrued product payables" on our Consolidated Balance Sheets included in this annual report.

Other Items

Duncan Energy Partners Transactions

Duncan Energy Partners was formed in September 2006 and did not acquire any assets prior to February 5, 2007, which was the date it completed its initial public offering of 14,950,000 common units and acquired controlling interests in certain midstream energy businesses of EPO. The business purpose of Duncan Energy Partners is to acquire, own and operate a diversified portfolio of midstream energy assets and to support the growth objectives of EPO and other affiliates under common control. Duncan Energy Partners is engaged in the business of transporting and storing NGLs and petrochemical products and gathering, transporting, storing and marketing of natural gas.

At December 31, 2008, Duncan Energy Partners is owned 99.3% by its limited partners and 0.7% by its general partner, DEP GP, which is a wholly owned subsidiary of EPO. DEP GP is responsible for managing the business and operations of Duncan Energy Partners. DEP Operating Partnership L.P. ("DEP OLP"), a wholly owned subsidiary of Duncan Energy Partners, conducts substantially all of Duncan Energy Partners' business.

At December 31, 2008, EPO owned approximately 74.1% of Duncan Energy Partners' limited partner interests and 100.0% of its general partner.

DEP I Midstream Businesses. On February 5, 2007, EPO contributed a 66.0% controlling equity interest in each of the DEP I Midstream Businesses (defined below) to Duncan Energy Partners in a dropdown of assets. EPO retained the remaining 34.0% equity interest in each of the DEP I Midstream Businesses. The DEP I Midstream Businesses consist of (i) Mont Belvieu Caverns, LLC ("Mont Belvieu Caverns"); (ii) Acadian Gas, LLC ("Acadian Gas"); (iii) Enterprise Lou-Tex Propylene Pipeline L.P. ("Lou-Tex Propylene"), including its general partner; (iv) Sabine Propylene Pipeline L.P. ("Sabine Propylene'), including its general partner; and (v) South Texas NGL Pipelines, LLC ("South Texas NGL").

As consideration for controlling equity interests in the DEP I Midstream Businesses and reimbursement for capital expenditures related to these businesses, Duncan Energy Partners distributed to EPO (i) $260.6 million of the $290.5 million of net proceeds from its initial public offering to EPO, (ii) $198.9 million in borrowings under its revolving credit facility and (iii) a net 5,351,571 common units of Duncan Energy Partners. See Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding the debt obligations of Duncan Energy Partners.

DEP II Midstream Businesses. On December 8, 2008, Duncan Energy Partners entered into a Purchase and Sale Agreement (the "DEP II Purchase Agreement") with EPO and Enterprise GTM Holdings L.P. ("Enterprise GTM," a wholly owned subsidiary of EPO). Pursuant to the DEP II Purchase Agreement, DEP OLP acquired 100.0% of the membership interests in Enterprise Holding III, LLC ("Enterprise III") from Enterprise GTM, thereby acquiring a 66.0% general partner interest in Enterprise GC, a 51.0% general partner interest in Enterprise Intrastate and a 51.0% membership interest in Enterprise

Texas. Collectively, we refer to Enterprise GC, Enterprise Intrastate and Enterprise Texas as the "DEP II Midstream Businesses." EPO was the sponsor of this second dropdown transaction. Enterprise GTM retained the remaining limited partner and member interests in the DEP II Midstream Businesses.

As consideration for controlling equity interests in the DEP II Midstream Businesses, EPO received $280.5 million in cash and 37,333,887 Class B limited partner units having a market value of $449.5 million from Duncan Energy Partners. The Class B limited partner units automatically converted to common units of Duncan Energy Partners on February 1, 2009. The total value of the consideration provided to EPO and Enterprise GTM was $730.0 million. The cash portion of the consideration provided by Duncan Energy Partners in this dropdown transaction was derived from borrowings under a term loan. See Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding the debt obligations of Duncan Energy Partners.

Generally, the DEP II dropdown transaction documents provide that to the extent that the DEP II Midstream Businesses generate cash sufficient to pay distributions to their partners or members, such cash will be distributed to Enterprise III (a wholly owned by Duncan Energy Partners) and Enterprise GTM (our wholly owned subsidiary) in an amount sufficient to generate an aggregate annualized return on their respective investments of 11.85%. Distributions in excess of this amount will be distributed 98.0% to Enterprise GTM and 2.0% to Enterprise III. The initial annual fixed return amount of 11.85% will be increased by 2.0% each calendar year beginning January 1, 2010. For example, the fixed return in 2010, assuming no other adjustments, would be 102% of 11.85%, or 12.087%.

Duncan Energy Partners paid a pro rated cash distribution of $0.1115 per unit on the Class B units with respect to the fourth quarter of 2008.

Insurance Matters

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other coverages, the scope and amounts of which are customary and sufficient for the nature and extent of our operations. While we believe EPCO maintains adequate insurance coverage on our behalf, insurance will not cover every type of damages or interruption that might occur. If we were to incur a significant liability for which we were not fully insured, it could have a material impact on our consolidated financial position, results of operations and cash flows. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient to reimburse us for our repair costs or lost income. Any event that interrupts the revenues generated by our consolidated operations, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to pay distributions to our partners and, accordingly, adversely affect the market price of our common units.

For windstorm events such as hurricanes and tropical storms, EPCO's deductible for onshore physical damage is $10.0 million per storm. For offshore assets, the windstorm deductible is $10.0 million per storm plus a one-time $15.0 million aggregate deductible per policy period. For non-windstorm events, EPCO's deductible for onshore and offshore physical damage is $5.0 million per occurrence. In meeting the deductible amounts, property damage costs are aggregated for EPCO and its affiliates, including us. Accordingly, our exposure with respect to the deductibles may be equal to or less than the stated amounts depending on whether other EPCO or affiliate assets are also affected by an event.

To qualify for business interruption coverage in connection with a windstorm event, covered assets must be out-of-service in excess of 60 days for onshore assets and 75 days for offshore assets. To qualify for business interruption coverage in connection with a non-windstorm event, covered onshore and offshore assets must be out-of-service in excess of 60 days.

In the third quarter of 2008, our onshore and offshore facilities located along the Gulf Coast of Texas and Louisiana were adversely impacted by Hurricanes Gustav and Ike. The disruptions in natural gas, NGL and crude oil production caused by these storms resulted in decreased volumes for some of our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which, in turn, caused a decrease in gross operating margin from these operations. As a result of our allocated share of EPCO's insurance deductibles for windstorm coverage, we expensed a combined $47.9 million of repair costs for property damage in connection with these two storms. We expect to file property damage insurance claims to the extent repair costs exceed deductible amounts. Due to the recent nature of these storms, we are still evaluating the total cost of repairs and the potential for business interruption claims on certain assets.

See Note 21 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for more information regarding insurance matters.

Contractual Obligations

The following table summarizes our significant contractual obligations at December 31, 2008 (dollars in thousands).

		Payment or Settlement due by Period			
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**More than 5 years**
Scheduled maturities of long-term debt (1)	$ 9,046,046	$ --	$ 1,488,250	$ 2,267,596	$ 5,290,200
Estimated cash payments for interest (2)	$ 9,351,928	$ 544,658	$ 993,886	$ 821,123	$ 6,992,261
Operating lease obligations (3)	$ 331,419	$ 32,299	$ 55,372	$ 51,547	$ 192,201
Purchase obligations: (4)					
Product purchase commitments:					
Estimated payment obligations:					
Natural gas	$ 5,225,141	$ 323,309	$ 1,150,102	$ 1,148,610	$ 2,603,120
NGLs	$ 1,923,792	$ 969,870	$ 272,672	$ 272,500	$ 408,750
Petrochemicals	$ 1,746,138	$ 685,643	$ 624,393	$ 268,418	$ 167,684
Other	$ 37,455	$ 19,202	$ 6,781	$ 5,970	$ 5,502
Underlying major volume commitments:					
Natural gas (in BBtus)	981,955	56,650	209,075	214,730	501,500
NGLs (in MBbls)	56,622	23,576	9,446	9,440	14,160
Petrochemicals (in MBbls)	67,696	24,949	23,848	11,665	7,234
Service payment commitments	$ 529,402	$ 52,614	$ 100,403	$ 93,167	$ 283,218
Capital expenditure commitments (5)	$ 521,262	$ 521,262	$ --	$ --	$ --
Other long-term liabilities, as reflected in our Consolidated Balance Sheet (6)	$ 81,277	$ --	$ 14,710	$ 7,573	$ 58,994
Total	$ 28,793,860	$ 3,148,857	$ 4,706,569	$ 4,936,504	$ 16,001,930

(1) Represents our scheduled future maturities of consolidated debt obligations for the periods indicated. See Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our debt obligations.

(2) Our estimated cash payments for interest are based on the principle amount of consolidated debt obligations outstanding at December 31, 2008. With respect to variable-rate debt, we applied the weighted-average interest rates paid during 2008. See Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding variable interest rates charged in 2008 under our credit agreements. In addition, our estimate of cash payments for interest gives effect to interest rate swap agreements in place at December 31, 2008. See Note 7 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. Our estimated cash payments for interest are significantly influenced by the long-term maturities of our $550.0 million Junior Notes A (due August 2066) and $682.7 million Junior Notes B (due January 2068). Our estimated cash payments for interest assume that the Junior Note obligations are not called prior to maturity.

(3) Primarily represents operating leases for (i) underground caverns for the storage of natural gas and NGLs, (ii) leased office space with an affiliate of EPCO, (iii) a railcar unloading terminal in Mont Belvieu, Texas, and (iv) land held pursuant to right-of-way agreements.

(4) Represents enforceable and legally binding agreements to purchase goods or services based on the contractual terms of each agreement at December 31, 2008.

(5) Represents our short-term unconditional payment obligations relating to our capital projects.

(6) As presented on our Consolidated Balance Sheet at December 31, 2008, other long-term liabilities consist primarily of (i) liabilities for our asset retirement obligations and (ii) liabilities for environmental remediation costs. For information regarding our environmental remediation costs and asset retirement obligations, see Notes 2 and 10 respectively, of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

For additional information regarding our significant contractual obligations involving operating leases and purchase obligations, see Note 20 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Off-Balance Sheet Arrangements

Except for the following information regarding debt obligations of certain unconsolidated affiliates, we have no off-balance sheet arrangements, as described in Item 303(a)(4)(ii) of Regulation S-K, that have or are reasonably expected to have a material current or future effect on our financial condition, revenues, expenses, results of operations, liquidity, capital expenditures or capital resources. The following information summarizes the significant terms of such unconsolidated debt obligations.

Poseidon. At December 31, 2008, Poseidon's debt obligations consisted of $109.0 million outstanding under its $150.0 million revolving credit facility. Amounts borrowed under this facility mature in May 2011 and are secured by substantially all of Poseidon's assets.

Evangeline. At December 31, 2008, Evangeline's debt obligations consisted of (i) $8.2 million in principal amount of 9.90% fixed rate Series B senior secured notes due December 2010 and (ii) a $7.5 million subordinated note payable. Duncan Energy Partners had $1.0 million of letters of credit outstanding on December 31, 2008 that were furnished on behalf of Evangeline's debt.

Summary of Related Party Transactions

The following table summarizes our related party transactions for the periods indicated (dollars in thousands).

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Revenues from consolidated operations			
EPCO and affiliates	$ 121,201	$ 67,635	$ 98,671
Energy Transfer Equity and subsidiaries	561,727	294,441	--
Unconsolidated affiliates	396,879	290,640	304,559
Total	$ 1,079,807	$ 652,716	$ 403,230
Cost of sales			
EPCO and affiliates	$ 59,173	$ 33,827	$ 86,050
Energy Transfer Equity and subsidiaries	173,883	26,889	--
Unconsolidated affiliates	90,836	41,474	42,166
Total	$ 323,892	$ 102,190	$ 128,216
Operating costs and expenses			
EPCO and affiliates	$ 314,612	$ 260,716	$ 225,487
Energy Transfer Equity and subsidiaries	18,284	8,267	--
Unconsolidated affiliates	(10,388)	(8,709)	(10,560)
Total	$ 322,508	$ 260,274	$ 214,927
General and administrative expenses			
EPCO and affiliates	$ 59,058	$ 56,518	$ 41,265
Unconsolidated affiliates	(51)	--	--
Total	$ 59,007	$ 56,518	$ 41,265
Other income (expense)			
EPCO and affiliates	$ (274)	$ (170)	$ 680
Unconsolidated affiliates	--	--	262
Total	$ (274)	$ (170)	$ 942

For additional information regarding our related party transactions, see Note 17 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. For information regarding certain business relationships and related transactions, see Item 13 of this annual report.

We have an extensive and ongoing relationship with EPCO and its affiliates, including TEPPCO. Our revenues from EPCO and affiliates are primarily associated with sales of NGL products. Our expenses with EPCO and affiliates are primarily due to (i) reimbursements we pay EPCO in connection with an administrative services agreement (the "ASA") and (ii) purchases of NGL products. TEPPCO is an affiliate of ours due to the common control relationship of both entities. Enterprise GP Holdings acquired non-controlling ownership interests in both ETE GP and Energy Transfer Equity in May 2007. As a result of this transaction, ETE GP and Energy Transfer Equity became related parties to us.

Many of our unconsolidated affiliates perform supporting or complementary roles to our consolidated business operations. The majority of our revenues from unconsolidated affiliates relate to natural gas sales to a Louisiana affiliate. The majority of our expenses with unconsolidated affiliates pertain to payments we make to K/D/S Promix, L.L.C. for NGL transportation, storage and fractionation services and to Jonah for natural gas purchases.

On February 5, 2007, our consolidated subsidiary, Duncan Energy Partners, completed an underwritten initial public offering of its common units. Duncan Energy Partners was formed in September 2006 as a Delaware limited partnership to, among other things, acquire ownership interests in certain of our midstream energy businesses. For additional information regarding Duncan Energy Partners, see "Other Items – Duncan Energy Partners Transactions" within this section.

Non-GAAP Reconciliations

The following table presents a reconciliation of our measurement of total non-GAAP gross operating margin to GAAP operating income and income before provision for income taxes, minority interest and the cumulative effect of change in accounting principle (dollars in thousands):

	For the Year the Ended December 31,		
	2008	2007	2006
Total segment gross operating margin	$ 2,057,469	$ 1,492,068	$ 1,362,449
Adjustments to reconcile total gross operating margin to operating income:			
Depreciation, amortization and accretion in operating costs and expenses	(555,370)	(513,840)	(440,256)
Operating lease expense paid by EPCO	(2,038)	(2,105)	(2,109)
Gain (loss) from asset sales and related transactions in operating costs and expenses	3,735	(5,391)	3,359
General and administrative costs	(90,550)	(87,695)	(63,391)
Operating income	1,413,246	883,037	860,052
Other expense, net	(391,448)	(303,463)	(229,967)
Income before provision for income taxes, minority interest and the cumulative effect of change in accounting principle	$ 1,021,798	$ 579,574	$ 630,085

EPCO subleases to us 100 railcars for $1 per year (the "retained leases"). These subleases are part of the ASA that we executed with EPCO in connection with our formation in 1998. EPCO holds this equipment pursuant to operating leases for which it has retained the corresponding cash lease payment obligation. We record the full value of such lease payments made by EPCO as a non-cash related party operating expense, with the offset to partners' equity recorded as a general contribution to our partnership. Apart from the partnership interests we granted to EPCO at our formation, EPCO does not receive any additional ownership rights as a result of its contribution to us of the retained leases. We exercised our election under the retained leases to purchase a cogeneration unit in December 2008 for $2.3 million. For additional information regarding the ASA and the retained leases, see Item 13 of this annual report.

Recent Accounting Pronouncements

The accounting standard setting bodies have recently issued the following accounting guidance that will affect our future financial statements:

- Statement of Financial Accounting Standards ("SFAS") 141(R), Business Combinations;

- FASB Staff Position SFAS 142-3, Determination of the Useful Life of Intangible Assets;

- SFAS 157, Fair Value Measurements;

- SFAS 160, Noncontrolling Interests in Consolidated Financial Statements – An amendment of ARB 51;

- SFAS 161, Disclosures about Derivative Instruments and Hedging Activities – An Amendment of SFAS 133;
- Emerging Issues Task Force ("EITF") 08-6, Equity Method Investment Accounting Considerations; and

- EITF 07-4, Application of the Two Class Method Under SFAS 128, Earnings Per Share, to Master Limited Partnerships.

For additional information regarding recent accounting pronouncements, see Note 3 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk.*

We are exposed to financial market risks, including changes in commodity prices, interest rates and foreign exchange rates. We may use financial instruments (e.g., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the types of risks we attempt to hedge are those related to (i) the variability of future earnings, (ii) fair values of certain debt obligations and (iii) cash flows resulting from changes in applicable interest rates, commodity prices or exchange rates.

We routinely review our outstanding financial instruments in light of current market conditions. If market conditions warrant, some financial instruments may be closed out in advance of their contractual settlement dates thus realizing income or loss depending on the specific hedging criteria. When this occurs, we may enter into a new financial instrument to reestablish the hedge to which the closed instrument relates.

The following table presents gains (losses) recorded in net income attributable to our interest rate risk and commodity risk hedging transactions for the periods indicated (dollars in thousands). These amounts do not present the corresponding gains (losses) attributable to the underlying hedged items.

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Interest Rate Risk Hedging Portfolio:			
EPO:			
Reclassification of cash flow hedge amounts from AOCI, net	$ 4,409	$ 5,429	$ 4,234
Other gains (losses) from derivative transactions	5,340	(8,934)	(5,195)
Duncan Energy Partners:			
Ineffective portion of cash flow hedges	(5)	(155)	--
Reclassification of cash flow hedge amounts from AOCI, net	(2,008)	350	--
Total hedging gains (losses), net, in consolidated interest expense	$ 7,736	$ (3,310)	$ (961)
Commodity Risk Hedging Portfolio:			
EPO:			
Reclassification of cash flow hedge amounts from AOCI, net - natural gas marketing activities	$ (30,175)	$ (3,299)	$ (1,327)
Reclassification of cash flow hedge amounts from AOCI, net - NGL and petrochemical operations	(28,232)	(4,564)	13,891
Other gains (losses) from derivative transactions	29,772	(20,712)	(2,307)
Total hedging gains (losses), net, in consolidated operating costs and expenses	$ (28,635)	$ (28,575)	$ 10,257

The following table provides additional information regarding derivative instruments as presented in our Consolidated Balance Sheets at the dates indicated (dollars in thousands):

	At December 31, 2008	2007
Current assets:		
Derivative assets:		
Interest rate risk hedging portfolio	$ 7,780	$ --
Commodity risk hedging portfolio	185,762	341
Foreign currency risk hedging portfolio	9,284	1,308
Total derivative assets – current	$ 202,826	$ 1,649
Other assets:		
Interest rate risk hedging portfolio	$ 38,939	$ 14,744
Total derivative assets – long-term	$ 38,939	$ 14,744
Current liabilities:		
Derivative liabilities:		
Interest rate risk hedging portfolio	$ 5,910	$ 22,209
Commodity risk hedging portfolio	281,142	19,575
Foreign currency risk hedging portfolio	109	27
Total derivative liabilities – current	$ 287,161	$ 41,811
Other liabilities:		
Interest rate risk hedging portfolio	3,889	3,080
Commodity risk hedging portfolio	233	--
Total derivative liabilities– long-term	$ 4,122	$ 3,080

The following table presents gains (losses) recorded in other comprehensive income (loss) for cash flow hedges associated with our interest rate risk, commodity risk and foreign currency risk hedging portfolios (dollars in thousands). These amounts do not present the corresponding gains (losses) attributable to the underlying hedged items.

	For the Year Ended December 31, 2008	2007	2006
Interest Rate Risk Hedging Portfolio:			
EPO:			
Gains (losses) on cash flow hedges	$ (20,772)	$ 17,996	$ 11,196
Reclassification of cash flow hedge amounts to net income, net	(4,409)	(5,429)	(4,234)
Duncan Energy Partners:			
Losses on cash flow hedges	(7,989)	(3,271)	--
Reclassification of cash flow hedge amounts to net income, net	2,008	(350)	--
Total interest rate risk hedging gains (losses), net	(31,162)	8,946	6,962
Commodity Risk Hedging Portfolio:			
EPO:			
Natural gas marketing activities:			
Losses on cash flow hedges	(30,642)	(3,125)	(1,034)
Reclassification of cash flow hedge amounts to net income, net	30,175	3,299	1,327
NGL and petrochemical operations:			
Gains (losses) on cash flow hedges	(120,223)	(22,735)	9,976
Reclassification of cash flow hedge amounts to net income, net	28,232	4,564	(13,891)
Total commodity risk hedging gains (losses), net	(92,458)	(17,997)	(3,622)
Foreign Currency Risk Hedging Portfolio:			
Gains on cash flow hedges	9,286	1,308	--
Total foreign currency risk hedging gains (losses), net	9,286	1,308	--
Total cash flow hedge amounts in other comprehensive income	$ (114,334)	$ (7,743)	$ 3,340

The following information summarizes the principal elements of our interest rate risk, commodity risk and foreign currency risk hedging portfolios. For amounts recorded in net income and other comprehensive income and on our balance sheet related to our consolidated hedging activities, please refer to the preceding tables.

Interest Rate Risk Hedging Portfolio

Our interest rate exposure results from variable and fixed rate borrowings under various debt agreements. The following information summarizes significant components of our interest rate risk hedging portfolio:

Fair value hedges – EPO interest rate swaps

We manage a portion of our interest rate exposure by utilizing interest rate swaps and similar arrangements, which allow us to convert a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt. At December 31, 2008, we had four interest rate swap agreements outstanding having an aggregate notional value of $400.0 million that were accounted for as fair value hedges. The aggregate fair value of these interest rate swaps at December 31, 2008, was $46.7 million (an asset), with an offsetting increase in the fair value of the underlying debt. There were eleven interest rate swaps outstanding at December 31, 2007 having an aggregate fair value of $12.9 million (an asset).

The following table summarizes our interest rate swaps outstanding at December 31, 2008.

Hedged Fixed Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Fixed to Variable Rate (1)	Notional Value
Senior Notes C, 6.375% fixed rate, due Feb. 2013	1	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 5.015%	$100.0 million
Senior Notes G, 5.60% fixed rate, due Oct. 2014	3	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.60% to 5.297%	$300.0 million

(1) The variable rate indicated is the all-in variable rate for the current settlement period.

We have designated these interest rate swaps as fair value hedges under SFAS 133 since they mitigate changes in the fair value of the underlying fixed rate debt. As effective fair value hedges, an increase in the fair value of these interest rate swaps is equally offset by an increase in the fair value of the underlying hedged debt. The offsetting changes in fair value have no effect on current period interest expense.

The following table shows the effect of hypothetical price movements on the estimated fair value of our interest rate swap portfolio and the related change in fair value of the underlying debt at the dates indicated (dollars in millions).

Scenario	Resulting Classification	Swap Fair Value at December 31, 2007	Swap Fair Value at December 31, 2008	Swap Fair Value at February 3, 2009
FV assuming no change in underlying interest rates	*Asset*	$ 12.9	$ 46.7	$ 36.3
FV assuming 10% increase in underlying interest rates	*Asset (Liability)*	(7.4)	42.4	31.1
FV assuming 10% decrease in underlying interest rates	*Asset*	33.1	51.1	41.5

The fair value of the interest rate swaps excludes related hedged amounts we have recorded in earnings. The change in fair value between December 31, 2008 and February 3, 2009 is primarily due to an increase in market interest rates relative to the interest rates used to determine the fair value of our financial instruments at December 31, 2008. The underlying floating LIBOR forward interest rate curve used to determine the February 3, 2009 fair values ranged from approximately 1.3% to 3.8% using 6-month reset periods ranging from February 2008 to March 2014.

Cash flow hedges – EPO treasury locks

We may enter into treasury rate lock transactions ("treasury locks") to hedge U.S. treasury rates related to its anticipated issuances of debt. Each of our treasury lock transactions was designated as a cash flow hedge. Gains or losses on the termination of such instruments are reclassified into net income (as a component of interest expense) using the effective interest method over the estimated term of the underlying fixed-rate debt. At December 31, 2008, we had no treasury lock financial instruments outstanding. At December 31, 2007, the aggregate notional value of our treasury lock financial instruments was $600.0 million, which had a total fair value (a liability) of $19.6 million. We terminated a number of treasury lock financial instruments during 2008 and 2007. These terminations resulted in realized losses of $40.4 million in 2008 and gains of $48.8 million in 2007.

We expect to reclassify $1.6 million of cumulative net gains from our interest rate risk cash flow hedges into net income (as a decrease to interest expense) during 2009.

Cash flow hedges – Duncan Energy Partners' interest rate swaps

At December 31, 2008, Duncan Energy Partners had interest rate swap agreements outstanding having an aggregate notional value of $175.0 million. These swaps were accounted for as cash flow hedges. The purpose of these financial instruments is to reduce the sensitivity of Duncan Energy Partners' earnings to the variable interest rates charged under its revolving credit facility. The aggregate fair value of these interest rate swaps at December 31, 2008 and 2007 was a liability of $9.8 million and $3.8 million, respectively. Duncan Energy Partners expects to reclassify $6.0 million of cumulative net losses from its interest rate risk cash flow hedges into net income (as an increase to interest expense) during 2009.

The following table summarizes Duncan Energy Partners' interest rate swaps outstanding at December 31, 2008.

Hedged Variable Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Variable to Fixed Rate (1)	Notional Value
DEP I Revolving Credit Facility, due Feb. 2011	3	Sep. 2007 to Sep. 2010	Sep. 2010	1.47% to 4.62%	$175.0 million

(1) Amounts receivable from or payable to the swap counterparties are settled every three months (the "settlement period").

As cash flow hedges, any increase or decrease in fair value (to the extent effective) would be recorded in other comprehensive income (loss) and amortized into earnings based on the settlement period hedged. Any ineffectiveness is recorded directly into earnings as an increase in interest expense.

The following table shows the effect of hypothetical price movements on the estimated fair value of Duncan Energy Partners' interest rate swap portfolio (dollars in millions).

		Swap Fair Value at		
Scenario	Resulting Classification	December 31, 2007	December 31, 2008	February 3, 2009
FV assuming no change in underlying interest rates	*Liability*	$ (3.8)	$ (9.8)	$ (9.4)
FV assuming 10% increase in underlying interest rates	*Liability*	(2.2)	(9.4)	(9.0)
FV assuming 10% decrease in underlying interest rates	*Liability*	(5.3)	(10.2)	(9.8)

Commodity Risk Hedging Portfolio

Our commodity risk hedging portfolio was impacted by a significant decline in natural gas prices during the second half of 2008. As a result of the global recession, commodity prices have continued to be volatile during the first quarter of 2009. We may experience additional losses related to our commodity risk hedging portfolio in 2009.

The prices of natural gas, NGLs and certain petrochemical products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the price risks associated with such products, we may enter into commodity financial instruments.

The primary purpose of our commodity risk management activities is to reduce our exposure to price risks associated with (i) natural gas purchases, (ii) the value of NGL production and inventories, (iii) related firm commitments, (iv) fluctuations in transportation revenues where the underlying fees are based on natural gas index prices and (v) certain anticipated transactions involving either natural gas, NGLs or certain petrochemical products. From time to time, we inject natural gas into storage and may utilize hedging instruments to lock in the value of its inventory positions. The commodity financial instruments we utilize are settled in cash.

We have segregated our commodity financial instruments portfolio between those financial instruments utilized in connection with our natural gas marketing activities and those used in connection with its NGL and petrochemical operations.

A significant number of the financial instruments in this portfolio hedge the purchase of physical natural gas. If natural gas prices fall below the price stipulated in such financial instruments, we recognize a liability for the difference; however, if prices partially or fully recover, this liability would be reduced or eliminated, as appropriate. Our restricted cash balance at December 31, 2008 was $203.8 million in order to meet commodity exchange deposit requirements and the negative change in the fair value of our natural gas hedge positions.

Natural gas marketing activities

At December 31, 2008 and 2007, the aggregate fair value of those financial instruments utilized in connection with our natural gas marketing activities was an asset of $6.5 million and a liability of $0.3 million, respectively. Almost all of the financial instruments within this portion of the commodity financial instruments portfolio are accounted for using mark-to-market accounting, with a small number accounted for as cash flow hedges. We did not have any cash flow hedges related to our natural gas marketing activities at December 31, 2008.

The following table shows the effect of hypothetical price movements on the estimated fair value of this component of the overall portfolio at the dates presented (dollars in millions):

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2007**	**December 31, 2008**	**February 3, 2009**
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ (0.3)	$ 6.5	$ 13.9
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(1.4)	2.7	9.4
FV assuming 10% decrease in underlying commodity prices	*Asset*	0.7	9.9	18.3

The change in fair value of the instruments between December 31, 2008 and February 3, 2009 is primarily due to a decrease in natural gas prices.

NGL and petrochemical operations

At December 31, 2008 and 2007, the aggregate fair value of those financial instruments utilized in connection with our NGL and petrochemical operations were liabilities of $102.1 million and $19.0 million, respectively. Almost all of the financial instruments within this portion of the commodity financial instruments portfolio are accounted for as cash flow hedges, with a small number accounted for using mark-to-market accounting. We expect to reclassify $114.0 million of cumulative net losses from these cash flow hedges into net income (as an increase in operating costs and expenses) during 2009.

We have employed a program to economically hedge a portion of our earnings from natural gas processing in the Rocky Mountain region. This program consists of (i) the forward sale of a portion of our expected equity NGL production volumes at fixed prices through 2009 and (ii) the purchase, using commodity financial instruments, of the amount of natural gas expected to be consumed as plant thermal reduction ("PTR") in the production of such equity NGL volumes. The objective of this strategy is to hedge a level of gross margins (i.e., NGL sales revenues less actual costs for PTR and the gain or loss on the PTR hedge) associated with the forward sales contracts by fixing the cost of natural gas used for PTR, through the use of commodity financial instruments. At December 31, 2008, this hedging program had hedged future expected gross margins (before plant operating expenses) of $483.9 million on 22.5 million barrels of forecasted NGL forward sales transactions extending through 2009.

Our NGL forward sales contracts are not accounted for as financial instruments under SFAS 133 since they meet normal purchase and sale exception criteria; therefore, changes in the aggregate economic value of these sales contracts are not reflected in net income and other comprehensive income until the volumes are delivered to customers. On the other hand, the commodity financial instruments used to purchase the related quantities of PTR (i.e., "PTR hedges") are accounted for as cash flow hedges; therefore, changes in the aggregate fair value of the PTR hedges are presented in other comprehensive income (loss). Once the forecasted NGL forward sales transactions occur, any realized gains and losses on the cash flow hedges would be reclassified into net income in that period.

Prior to actual settlement, if the market price of natural gas is less than the price stipulated in a commodity financial instrument, we recognize an unrealized loss in other comprehensive loss for the excess of the natural gas price stated in the hedge over the market price. To the extent that we realize such financial losses upon settlement of the instrument, the losses are added to the actual cost we pay for PTR, which would then be based on the lower market price. Conversely, if the market price of natural gas is greater than the price stipulated in such hedges, we recognize an unrealized gain in other comprehensive income for the excess of the market price over the natural gas price stated in the PTR hedge. If realized, the gains on the financial instrument would serve to reduce the actual cost paid for PTR, which would then be based on the higher market price. The net effect of these hedging relationships is that our total cost of natural gas used for PTR approximates the amount it originally hedged under this program.

The following table shows the effect of hypothetical price movements on the estimated fair value of this component of the overall portfolio at the dates presented (dollars in millions):

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2007**	**December 31, 2008**	**February 3, 2009**
FV assuming no change in underlying commodity prices	*Liability*	$ (19.0)	$ (102.1)	$ (111.6)
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	11.3	(94.0)	(109.2)
FV assuming 10% decrease in underlying commodity prices	*Liability*	(49.2)	(110.1)	(114.1)

The change in fair value of the NGL and petrochemical portfolio between December 31, 2008 and February 3, 2009 is primarily due to a decrease in natural gas prices.

Foreign Currency Hedging Portfolio

We are exposed to foreign currency exchange rate risk primarily through a Canadian NGL marketing subsidiary. As a result, we could be adversely affected by fluctuations in the foreign currency exchange rate between the U.S. dollar and the Canadian dollar. We attempt to hedge this risk using foreign exchange purchase contracts to fix the exchange rate. Mark-to-market accounting is utilized for these contracts, which typically have a duration of one month. For the year ended December 31, 2008, we recorded minimal gains from these financial instruments.

In addition, we are exposed to foreign currency exchange rate risk through our Japanese Yen Term Loan Agreement ("Yen Term Loan") that EPO entered into in November 2008. As a result, we could be adversely affected by fluctuations in the foreign currency exchange rate between the U.S. dollar and the Japanese yen. We hedged this risk by entering into a foreign exchange purchase contract to fix the exchange rate. This purchase contract was designated as a cash flow hedge. At December 31, 2008, the fair value of this contract was $9.3 million. This contract will be settled in March 2009 upon repayment of the Yen Term Loan. Total interest expense under this loan agreement was $4.0 million, of which $1.7 million is the expected foreign currency loss, which will be recorded as interest expense.

Product Purchase Commitments

We have long and short-term purchase commitments for NGLs, petrochemicals and natural gas with several suppliers. The purchase prices that we are obligated to pay under these contracts are based on market prices at the time we take delivery of the volumes. For additional information regarding these commitments, see "Contractual Obligations" included under Item 7 of this annual report.

Fair Value Information

On January 1, 2008, we adopted the provisions of SFAS 157 that apply to financial assets and liabilities. SFAS 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. See Note 8 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding fair value disclosures pertaining to our financial assets and liabilities.

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) primarily includes the effective portion of the gain or loss on financial instruments designated and qualified as a cash flow hedge, foreign currency adjustments and Dixie's minimum pension liability adjustments. Amounts accumulated in other comprehensive income (loss) from cash flow hedges are reclassified into earnings in the same period(s) in which the hedged forecasted transactions (such as a forecasted forward sale of NGLs) affect earnings. If it becomes probable that the forecasted transaction will not occur, the net gain or loss in accumulated other comprehensive income (loss) must be immediately reclassified.

The following table presents the components of accumulated other comprehensive income (loss) at the dates indicated:

	At December 31, 2008	At December 31, 2007
Commodity financial instruments – cash flow hedges (1)	$ (114,077)	$ (21,619)
Interest rate financial instruments – cash flow hedges (1)	3,818	34,980
Foreign currency cash flow hedges (1)	10,594	1,308
Foreign currency translation adjustment (2)	(1,301)	1,200
Pension and postretirement benefit plans (3)	(751)	588
Total accumulated other comprehensive income (loss)	$ (101,717)	$ 16,457

(1) See Note 7 for additional information regarding these components of accumulated other comprehensive income (loss).
(2) Relates to transactions of our Canadian NGL marketing subsidiary.
(3) See Note 6 for additional information regarding pension and postretirement benefit plans.

The following table summarizes the components of other comprehensive income (loss) for the periods indicated:

	For Year Ended December 31, 2008	2007	2006
Other comprehensive income (loss):			
Cash flow hedges	$ (114,334)	$ (7,743)	$ 3,340
Change in funded status of pension and postretirement plans, net of tax	(1,339)	(52)	--
Foreign currency translation adjustment	(2,501)	2,007	(807)
Total other comprehensive income (loss)	$ (118,174)	$ (5,788)	$ 2,533

Item 8. ***Financial Statements and Supplementary Data***

Our consolidated financial statements, together with the independent registered public accounting firm's report of Deloitte & Touche LLP ("Deloitte & Touche") begin on page F-1 of this annual report.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*.**

None.

Item 9A. ***Controls and Procedures*.**

Disclosure Controls and Procedures

As of the end of the period covered by this Report, our management carried out an evaluation, with the participation of our general partner's chief executive officer (the "CEO") and our general partner's chief financial officer (the "CFO"), of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Based on this evaluation, as of the end of the period covered by this Report, the CEO and CFO concluded:

(i) that our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including the CEO and CFO, as appropriate to allow timely decisions regarding required disclosure; and

(ii) that our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There were no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) or in other factors during the fourth quarter of 2008, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

The certifications of our general partner's CEO and CFO required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as exhibits to this annual report.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING AS OF DECEMBER 31, 2008

The management of Enterprise Products Partners L.P. and its consolidated subsidiaries, including its chief executive officer and chief financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our internal control system was designed to provide reasonable assurance to Enterprise Products Partners' management and Board of Directors regarding the preparation and fair presentation of published financial statements. However, our management does not represent that our disclosure controls and procedures or internal controls over financial reporting will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only a reasonable, not an absolute, assurance that the objectives of the control system are met.

Our management assessed the effectiveness of Enterprise Products Partners' internal control over financial reporting as of December 31, 2008. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in *Internal Control—Integrated Framework*. This assessment included a review of the design and operating effectiveness of internal controls over financial reporting as well as the safeguarding of assets. Based on our assessment, we believe that, as of December 31, 2008, Enterprise Products Partners' internal control over financial reporting is effective based on those criteria.

Our Audit, Conflicts and Governance Committee is composed of directors who are not officers or employees of our general partner. It meets regularly with members of management, the internal auditors and the representatives of the independent registered public accounting firm to discuss the adequacy of Enterprise Products Partners' internal controls over financial reporting, financial statements and the nature, extent and results of the audit effort. Management reviews with the Audit, Conflicts and Governance Committee all of Enterprise Products Partners' significant accounting policies and assumptions affecting the results of operations. Both the independent registered public accounting firm and internal auditors have direct access to the Audit, Conflicts and Governance Committee without the presence of management.

Our independent registered public accounting firm has issued an attestation report on our internal control over financial reporting. That report is included within this Item 9A.

Pursuant to the requirements of Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended, this Annual Report on Internal Control Over Financial Reporting has been signed below by the following persons on behalf of the registrant and in the capacities indicated below on March 2, 2009.

/s/ Michael A. Creel	*/s/ W. Randall Fowler*
Name: Michael A. Creel	Name: W. Randall Fowler
Title: Chief Executive Officer of our general partner, Enterprise Products GP, LLC	Title: Chief Financial Officer of our general partner, Enterprise Products GP, LLC

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products GP, LLC and
Unitholders of Enterprise Products Partners L.P.
Houston, Texas

We have audited the internal control over financial reporting of Enterprise Products Partners L.P. and subsidiaries (the "Company") as of December 31, 2008, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting as of December 31, 2008. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's Board of Directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet and the related consolidated statements of operations, comprehensive income, cash flows, and partners' equity as of and for the year ended December

31, 2008 of the Company and our report dated March 2, 2009 expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 2, 2009

Item 9B. *Other Information*.

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*.

Partnership Management

As is commonly the case with publicly traded limited partnerships, we do not directly employ any of the persons responsible for the management or operations of our business. These functions are performed by the employees of EPCO pursuant to the ASA under the direction of the Board of Directors (the "Board") and executive officers of EPGP. For a description of the ASA, see "Certain Relationships and Related Transactions – Relationship with EPCO" under Item 13 of this annual report.

The executive officers of our general partner are elected for one-year terms and may be removed, with or without cause, only by the Board. Our unitholders do not elect the officers or directors of our general partner. Dan. L. Duncan, through his indirect control of EPGP, has the ability to elect, remove and replace at any time, all of the officers and directors of our general partner. Each member of the Board of our general partner serves until such member's death, resignation or removal. The employees of EPCO who served as directors of EPGP were Messrs. Dan L. Duncan, Michael A. Creel, W. Randall Fowler, Ralph S. Cunningham, Richard H. Bachmann and A. J. Teague.

Because we are a limited partnership and meet the definition of a "controlled company" under the listing standards of the NYSE, we are not required to comply with certain requirements of the NYSE. Accordingly, we have elected to not comply with Section 303A.01 of the NYSE Listed Company Manual, which would require that the Board of our general partner be comprised of a majority of independent directors. In addition, we have elected to not comply with Sections 303A.04 and 303A.05 of the NYSE Listed Company Manual, which would require that the Board of our general partner maintain a Nominating Committee and a Compensation Committee, each consisting entirely of independent directors.

Notwithstanding any contractual limitation on its obligations or duties, EPGP is liable for all debts we incur (to the extent not paid by us), except to the extent that such indebtedness or other obligations are non-recourse to EPGP. Whenever possible, EPGP intends to make any such indebtedness or other obligations non-recourse to itself.

Under our limited partnership agreement and subject to specified limitations, we will indemnify to the fullest extent permitted by Delaware law, from and against all losses, claims, damages or similar events any director or officer, or while serving as director or officer, any person who is or was serving as a tax matters member or as a director, officer, tax matters member, employee, partner, manager, fiduciary or trustee of our partnership or any of our affiliates. Additionally, we will indemnify to the fullest extent permitted by law, from and against all losses, claims, damages or similar events any person who is or was an employee (other than an officer) or agent of our partnership.

Corporate Governance

We are committed to sound principles of governance. Such principles are critical for us to achieve our performance goals, and maintain the trust and confidence of investors, employees, suppliers, business partners and stakeholders.

A key element for strong governance is independent members of the Board of Directors. Pursuant to the NYSE listing standards, a director will be considered independent if the Board determines that he or she does not have a material relationship with EPGP or us (either directly or as a partner, unitholder or officer of an organization that has a material relationship with EPGP or us). Based on the foregoing, the Board has affirmatively determined that Messrs. Rex C. Ross, Charles M. Rampacek and E. William Barnett are "independent" directors under the NYSE rules.

Code of Conduct and Ethics and Corporate Governance Guidelines

EPGP has adopted a "Code of Conduct" that applies to all directors, officers and employees. This code sets out our requirements for compliance with legal and ethical standards in the conduct of our business, including general business principles, legal and ethical obligations, compliance policies for specific subjects, obtaining guidance, the reporting of compliance issues and discipline for violations of the code.

Our Code of Conduct also establishes policies applicable to our CEO, CFO, principal accounting officer and senior financial and other managers to prevent wrongdoing and to promote honest and ethical conduct, including ethical handling of actual and apparent conflicts of interest, compliance with applicable laws, rules and regulations, full, fair, accurate, timely and understandable disclosure in public communications and prompt internal reporting of violations of the code.

Governance guidelines, together with committee charter, provide the framework for effective governance. The Board has adopted the "Governance Guidelines of Enterprise Products Partners," which address several matters, including qualifications for directors, responsibilities of directors, retirement of directors, the composition and responsibility of the Audit, Conflicts and Governance ("ACG") Committee, the conduct and frequency of board and committee meetings, management succession, director access to management and outside advisors, director compensation, director orientation and continuing education, and annual self-evaluation of the board. The Board recognizes that effective governance is an on-going process, and thus, the Board will review the Governance Guidelines of Enterprise Products Partners annually or more often as deemed necessary.

We provide access through our website at www.epplp.com to current information relating to governance, including the Code of Conduct, the Governance Guidelines of Enterprise Products Partners and other matters impacting our governance principles. You may also contact our investor relations department at (866) 230-0745 for printed copies of these documents free of charge.

ACG Committee

The sole committee of the Board is its ACG Committee. In accordance with NYSE rules and Section 3(a)(58)(A) of the Securities Exchange Act of 1934, the Board has named three of its members to serve on its ACG Committee. The members of the ACG Committee are independent directors, free from any relationship with us or any of our subsidiaries that would interfere with the exercise of independent judgment.

The members of the ACG Committee must have a basic understanding of finance and accounting and be able to read and understand fundamental financial statements, and at least one member of the ACG Committee shall have accounting or related financial management expertise. The members of the ACG Committee are Messrs. Ross, Rampacek and Barnett. The Board has affirmatively determined that Mr. Rampacek satisfies the definition of "audit committee financial expert" as defined in Item 407(d) of Regulation S-K promulgated by the SEC.

The ACG Committee's duties are addressing audit and conflicts-related items and general corporate governance. From an audit and conflicts standpoint, the primary responsibilities of the ACG Committee include:

- review potential conflicts of interest, including related party transactions;
- monitoring the integrity of our financial reporting process and related systems of internal control;
- ensuring our legal and regulatory compliance and that of EPGP;
- overseeing the independence and performance of our independent public accountant;
- approving all services performed by our independent public accountant;
- providing for an avenue of communication among the independent public accountant, management, internal audit function and the Board;
- encouraging adherence to and continuous improvement of our policies, procedures and practices at all levels;
- reviewing areas of potential significant financial risk to our businesses; and
- approving awards granted under our long-term incentive plans.

If the Board believes that a particular matter presents a conflict of interest and proposes a resolution, the ACG Committee has the authority to review such matter to determine if the proposed resolution is fair and reasonable to us. Any matters approved by the ACG Committee are conclusively deemed to be fair and reasonable to our business, approved by all of our partners and not a breach by EPGP or the Board of any duties they may owe us or our unitholders.

Pursuant to its formal written charter, the ACG Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to our independent public accountants as well as any EPCO personnel whom it deems necessary in fulfilling its responsibilities. The ACG Committee has the ability to retain, at our expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties.

From a governance standpoint, the ACG Committee's primary duties and responsibilities are to develop and recommend to the Board a set of governance principles applicable to us and review such guidelines from time to time, making any changes that the ACG Committee deems necessary. The ACG Committee assists the Board in fulfilling its oversight responsibilities.

A copy of the ACG Committee charter is available on our website, www.epplp.com. You may also contact our investor relations department at (866) 230-0745 for a printed copy of this document free of charge.

NYSE Corporate Governance Listing Standards

On March 6, 2008, Michael A. Creel, our Chief Executive Officer, certified to the NYSE (as required by Section 303A.12(a) of the NYSE Listed Company Manual) that he was not aware of any violation by us of the NYSE's Corporate Governance listing standards as of March 6, 2008.

Executive Sessions of Non-Management Directors

The Board holds regular executive sessions in which non-management directors meet without any members of management present. The purpose of these executive sessions is to promote open and candid discussion among the non-management directors. During such executive sessions, one director is designated as the "presiding director," who is responsible for leading and facilitating such executive sessions. Currently, the presiding director is Mr. Barnett.

In accordance with NYSE rules, we have established a toll-free, confidential telephone hotline (the "Hotline") so that interested parties may communicate with the presiding director or with all the non-management directors as a group. All calls to this Hotline are reported to the chairman of the ACG Committee, who is responsible for communicating any necessary information to the other non-management directors. The number of our confidential Hotline is (877) 888-0002.

Directors and Executive Officers of EPGP

The following table sets forth the name, age and position of each of the directors and executive officers of EPGP at March 2, 2009. Each executive officer holds the same respective office shown below in the general partner of the Operating Partnership.

Name	Age	Position with EPGP
Dan L. Duncan (1)	76	Director and Chairman
Michael A. Creel (1)	55	Director, President and Chief Executive Officer
W. Randall Fowler (1)	52	Director, Executive Vice President and Chief Financial Officer
Richard H. Bachmann (1)	56	Director, Executive Vice President and Chief Legal Officer and Secretary
A.J. Teague (1)	63	Director, Executive Vice President and Chief Commercial Officer
Dr. Ralph S. Cunningham	68	Director
E. William Barnett (2,3)	76	Director
Rex C. Ross (2)	65	Director
Charles M. Rampacek (2)	65	Director
William Ordemann (1)	49	Executive Vice President and Chief Operating Officer
Michael J. Knesek (1)	54	Senior Vice President, Controller and Principal Accounting Officer
Christopher Skoog (1)	45	Senior Vice President
Thomas M. Zulim (1)	51	Senior Vice President
G. R. Cardillo (1)	51	Vice President

(1) Executive officer
(2) Member of ACG Committee
(3) Chairman of ACG Committee

The following information presents a brief history of the business experience of our directors and executive officers serving as of December 31, 2008:

Dan L. Duncan. Mr. Duncan was elected Chairman and a Director of EPGP in April 1998, Chairman and a Director of the general partner of EPO in December 2003, Chairman and a Director of EPE Holdings in August 2005 and Chairman and a Director of DEP GP in October 2006. Mr. Duncan served as the sole Chairman of EPCO from 1979 to December 2007. Mr. Duncan now serves as Group Co-Chairman of EPCO with his daughter, Ms. Randa Duncan Williams, who is also a Director of EPE Holdings. He also serves as an Honorary Trustee of the Board of Trustees of the Texas Heart Institute at Saint Luke's Episcopal Hospital.

Michael A. Creel. Mr. Creel was elected President and Chief Executive Officer of EPGP in August 2007. From June 2000 to August 2007, Mr. Creel served as Chief Financial Officer of EPGP and an Executive Vice President of EPGP from January 2001 to August 2007. Mr. Creel, a Certified Public Accountant, also served as a Senior Vice President of EPGP from November 1999 to January 2001.

In December 2007, Mr. Creel was elected Group Vice Chairman and Chief Financial Officer of EPCO. Prior to these elections in EPCO, Mr. Creel served as Chief Operating Officer from April 2005 to December 2007 and Chief Financial Officer from June 2000 to April 2005 for EPCO. He also serves as a Director of DEP GP and EPGP since October 2006 and 2005, respectively. Mr. Creel served as President, Chief Executive Officer and a Director of EPE Holdings from August 2005 through August 2007. In October 2005, Mr. Creel was elected a Director of Edge Petroleum Corporation, a publicly traded oil and natural gas exploration and production company.

W. Randall Fowler. Mr. Fowler was elected Executive Vice President and Chief Financial Officer of EPGP, EPE Holdings and DEP GP in August 2007. Mr. Fowler served as Senior Vice President and Treasurer of EPGP from February 2005 to August 2007 and of DEP GP from October 2006 to August 2007. In February 2006, Mr. Fowler became a Director of EPGP, EPE Holdings and of DEP. Mr. Fowler also served as Senior Vice President and Chief Financial Officer of EPE Holdings from August 2005 to August 2007.

Mr. Fowler was elected President and Chief Executive Officer of EPCO in December 2007. Prior to these elections, he served as Chief Financial Officer of EPCO from April 2005 to December 2007. Mr. Fowler, a Certified Public Accountant (inactive), joined Enterprise Products Partners as Director of Investor Relations in January 1999.

Richard H. Bachmann. Mr. Bachmann was elected an Executive Vice President, Chief Legal Officer and Secretary of EPGP and a Director of EPGP in February 2006. He previously served as a Director of EPGP from June 2000 to January 2004. Mr. Bachmann has served as a Director of EPO's general partner since December 2003 and has served as Executive Vice President, Chief Legal Officer and Secretary of EPE Holdings since August 2005.

Mr. Bachmann was elected Group Vice Chairman, Chief Legal Officer and Secretary of EPCO in December 2007. In October 2006, Mr. Bachmann was elected President, Chief Executive Officer and a Director of DEP GP. Mr. Bachmann was also elected a Director of EPE Holdings in February 2006. Since January 1999, Mr. Bachmann has served as a Director of EPCO. In November 2006, Mr. Bachmann was appointed an independent manager of Constellation Energy Partners LLC. Mr. Bachmann also serves as a member of the Audit, Compensation, Conflicts and Nominating and Governance Committees of Constellation Energy Partners LLC.

A.J. Teague. Mr. Teague was elected an Executive Vice President of EPGP in November 1999 and additionally as our Chief Commercial Officer and a Director in July 2008. Mr. Teague joined us in connection with our purchase of certain midstream energy assets from affiliates of Shell Oil Company in 1999. From 1998 to 1999, Mr. Teague served as President of Tejas Natural Gas Liquids, LLC.

Dr. Ralph S. Cunningham. Dr. Cunningham was elected a Director of EPGP in February 2006 and also served as a Director of EPGP from 1998 until March 2005. In addition to these duties, Dr. Cunningham served as Group Executive Vice President and Chief Operating Officer of EPGP from December 2005 to August 2007 and Interim President and Interim Chief Executive Officer from June 2007 to August 2007. Dr. Cunningham was elected President and Chief Executive Officer of EPE Holdings in August 2007. He served as Chairman and a Director of TEPPCO GP from March 2005 until November 2005.

Dr. Cunningham was elected a Group Vice Chairman of EPCO in December 2007 and served as a Director from 1987 to 1997. He serves as a Director of Tetra Technologies, Inc. (a publicly traded energy services and chemical company), EnCana Corporation (a Canadian publicly traded independent oil and natural gas company) and Agrium, Inc. (a Canadian publicly traded agricultural chemicals company). Dr. Cunningham retired in 1997 from CITGO Petroleum Corporation, where he had served as President and Chief Executive Officer since 1995.

E. William Barnett. Mr. Barnett was elected a Director of EPGP in March 2005. Mr. Barnett is a member of our ACG Committee and serves as its Chairman. Mr. Barnett practiced law with Baker Botts L.L.P. from 1958 until his retirement in 2004. In 1984, he became Managing Partner of Baker Botts L.L.P. and continued in that role for fourteen years until 1998. He was Senior Counsel to the firm from 1998 until June 2004, when he retired from the firm. Mr. Barnett served as Chairman of the Board of Trustees of Rice University from 1996 to July 2005.

Mr. Barnett is a Life Trustee of The University of Texas Law School Foundation; a Director of St. Luke's Episcopal Health System; and a Director and former Chairman of the Houston Zoo, Inc. (the operating arm of the Houston Zoo). He is a Director of Reliant Energy, Inc. (a publicly traded electric services company) and Westlake Chemical Corporation (a publicly traded chemical company). Mr. Barnett is Chairman of the Advisory Board of the Baker Institute for Public Policy at Rice University and a Director and former Chairman of the Greater Houston Partnership. Mr. Barnett served as a Trustee of the Baylor College of Medicine from 1993 until 2004.

Rex C. Ross. Mr. Ross was elected a Director of EPGP in October 2006 and is a member of its ACG Committee. Mr. Ross serves as a Director of Schlumberger Technology Corporation, the holding company for all Schlumberger Limited assets and entities in the United States. Prior to his executive retirement from Schlumberger Limited in May 2004, Mr. Ross held a number of executive management positions during his 11-year career with the company, including President of Schlumberger Oilfield Services North America; President, Schlumberger GeoQuest; and President of SchlumbergerSema North & South America. Mr. Ross also serves on the Board of Directors of Gulfmark Offshore, Inc. (a publicly traded offshore marine services company) and is a member of its Governance Committee.

Charles M. Rampacek. Mr. Rampacek was elected a Director of EPGP in October 2006 and is a member of its ACG Committee. Mr. Rampacek is currently a business and management consultant in the energy industry. Mr. Rampacek served as Chairman, Chief Executive Officer and President of Probex Corporation ("Probex"), an energy technology company that developed a proprietary used oil recovery process, from 2000 until his retirement in 2003. Prior to joining Probex, Mr. Rampacek was President and Chief Executive Officer of Lyondell-Citgo Refining L.P, a manufacturer of petroleum products, from 1996 through 2000. From 1982 to 1995, he held various executive positions with Tenneco Inc. and its energy-related subsidiaries, including President of Tenneco Gas Transportation Company, Executive Vice President of Tenneco Gas Operations and Senior Vice President of Refining and Supply. Mr. Rampacek also spent 16 years with Exxon Company USA, where he held various supervisory and management positions. Mr. Rampacek has been a Director of Flowserve Corporation since 1998 and is Chairman of its Corporate Governance and Nominating Committee and a member of its Organization and Compensation Committee.

In 2005, two complaints requesting recovery of certain costs were filed against former officers and directors of Probex as a result of the bankruptcy of Probex in 2003. These complaints were defended under Probex's director and officer insurance with American International Group, Inc. ("AIG") and settlement was reached and paid by AIG with bankruptcy court approval in the first half of 2006. An additional complaint was filed in 2005 against noteholders of certain Probex debt of which Mr. Rampacek was one. A settlement of $2 thousand was reached and approved by the bankruptcy court in the first half of 2006.

William Ordemann. Mr. Ordemann was elected an Executive Vice President and the Chief Operating Officer of EPGP in August 2007. He previously served as a Senior Vice President of EPGP from September 2001 to August 2007 and was a Vice President of EPGP from October 1999 to September 2001. Mr. Ordemann joined us in connection with our purchase of certain midstream energy assets from affiliates of Shell Oil Company in 1999. Prior to joining us, he was a Vice President of Shell Midstream Enterprises, LLC from January 1997 to February 1998, and Vice President of Tejas Natural Gas Liquids, LLC from February 1998 to September 1999.

Michael J. Knesek. Mr. Knesek, a Certified Public Accountant, was elected a Senior Vice President of EPGP in February 2005, having served as a Vice President of EPGP since August 2000. Mr. Knesek has been the Principal Accounting Officer and Controller of EPGP since August 2000, EPE Holdings since August 2005 and DEP GP since October 2006. He has served as Senior Vice President of EPE Holdings since August 2005 and of DEP GP since October 2006. Mr. Knesek has been the Controller of EPCO since 1990 and currently serves as one of its Senior Vice Presidents.

Christopher R. Skoog. Mr. Skoog joined the partnership in July 2007 as Senior Vice President of EPGP to develop and lead Enterprise Product Partners' Natural Gas Services and Marketing group. In July 2008, he also assumed responsibility for Enterprise Product Partners' non-regulated and intrastate natural gas pipeline and storage businesses. From 1995 to July 2007 he served in various executive positions at ONEOK, Inc. and ONEOK Partners L.P. He led ONEOK Energy Services from 1995 to 2005, and held senior executive positions in the partnership from 2005 to 2007.

Thomas M. Zulim. Since July 2008, Mr. Zulim has served as a Senior Vice President of EPGP and EPCO, Inc., with responsibility for the partnership's unregulated natural gas liquids (NGL) business. From March 2006 to July 2008, Mr. Zulim served as Senior Vice President, Human Resources, for both EPGP and EPCO, and served as Vice President, Human Resources, for both EPGP and EPCO from December 2004 to March 2006. He joined EPCO in 1999 as Director of Business Management for the NGL Fractionation business. Mr. Zulim came to EPCO from Shell Oil Company where, as an attorney, he practiced labor and employment law nationally for several years before joining Shell Midstream Enterprises in 1996 as Director of Business Development for its natural gas processing and NGL fractionation businesses. Mr. Zulim resumed practicing law with EPCO's Legal group in January 2002 until December 2004.

G. R. Cardillo. Mr. Cardillo joined us in connection with our purchase of certain petrochemical storage and propylene fractionation assets from affiliates of Ultramar Diamond Shamrock Corp. and Koch Industries Inc. ("Diamond Koch") in 2002. From 2000 to 2002, Mr. Cardillo served as a Vice President in charge of propylene commercial activities for Diamond Koch. Mr. Cardillo was elected a Vice President of EPGP in November 2004 and of DEP Holdings in September 2006. Mr. Cardillo has been an integral part of our Petrochemicals management team since joining us in 2002 and assumed leadership of this commercial function in June 2008.

Section 16(a) Beneficial Ownership Reporting Compliance

Under federal securities laws, EPGP, directors and executive officers of EPGP, and certain other officers, and any persons holding more than 10.0% of our common units are required to report their beneficial ownership of common units and any changes in their beneficial ownership levels to us and the SEC. Specific due dates for these reports have been established by regulation, and we are required to disclose in this annual report any failure to file this information within the specified timeframes. With the exception of the following late filing, all such reporting was done in a timely manner in 2008. Rex C. Ross filed a late Form 4 on February 29, 2008 for a transaction entered into in November 2007 by a Trust deemed beneficially owned by him.

Item 11. *Executive Compensation*.

Executive Officer Compensation

We do not directly employ any of the persons responsible for managing our partnership. Instead, we are managed by our general partner, the executive officers of which are employees of EPCO. Our reimbursement of EPCO's compensation costs is governed by the ASA (see Item 13 of this annual report).

Summary Compensation Table

The following table presents consolidated compensation amounts paid, accrued or otherwise expensed by us with respect to the years ended December 31, 2008, 2007 and 2006 for our CEO, CFO and three other most highly compensated executive officers as of December 31, 2008. Collectively, these five individuals were our "Named Executive Officers" for 2008. Compensation paid or awarded by us with respect to such Named Executive Officers reflects only that portion of compensation paid by EPCO allocated to us pursuant to the ASA, including an allocation of a portion of the cost of EPCO's equity-based long-term incentive plans.

Name and Principal Position	Year	Salary ($)	Bonus ($) (1)	Unit Awards ($) (2)	Option Awards ($) (3)	All Other Compensation ($) (4)	Total ($)
Michael A. Creel (CEO)	2008	$ 563,200	$ 552,000	$ 1,115,948	$ 90,902	$ 200,241	$ 2,522,291
	2007	361,808	365,370	517,707	44,449	108,017	1,397,351
	2006	306,000	125,000	303,622	23,613	71,812	830,047
W. Randall Fowler (CFO)	2008	190,781	131,250	386,864	31,390	62,646	802,931
	2007	213,145	129,720	297,976	25,033	53,425	719,299
	2006	215,875	70,000	173,874	14,242	40,601	514,592
A.J. Teague	2008	558,333	500,000	1,005,532	102,783	176,651	2,343,299
	2007	445,660	300,000	587,905	77,980	110,336	1,521,881
	2006	428,480	250,000	299,984	47,227	69,563	1,095,254
James H. Lytal (5)	2008	401,700	--	1,083,798	111,221	216,574	1,813,293
	2007	386,250	210,000	730,634	77,980	162,494	1,567,358
	2006	367,500	187,500	455,462	47,227	101,639	1,159,328
Richard H. Bachmann	2008	351,313	233,750	725,317	56,531	129,921	1,496,832
	2007	306,900	186,000	454,130	38,990	94,752	1,080,772
	2006	177,420	75,000	182,174	14,168	43,088	491,850

(1) Amounts represent discretionary annual cash awards accrued with respect to the years presented. Cash awards are paid in February of the following year (e.g., the cash awards for 2008 were paid in February 2009).
(2) Amounts represent expense recognized in accordance with SFAS 123(R) with respect to restricted unit awards issued under the EPCO 1998 Plan and Employee Partnership profits interests awards.
(3) Amounts represent expense recognized in accordance with SFAS 123(R) with respect to unit options issued under the EPCO 1998 Plan and EPD 2008 LTIP.
(4) Amounts primarily represent (i) matching contributions under funded, qualified, defined contribution retirement plans, (ii) quarterly distributions paid on incentive plan awards and (iii) the imputed value of life insurance premiums paid on behalf of the officer.
(5) Mr. Lytal resigned from the company in January 2009.

Compensation Discussion and Analysis

With respect to our Named Executive Officers, compensation paid or awarded by us for the last three fiscal years reflects only that portion of compensation paid by EPCO allocated to us pursuant to the ASA, including an allocation of a portion of the cost of equity-based long-term incentive plans of EPCO. Dan L. Duncan controls EPCO and has ultimate decision-making authority with respect to the compensation of our Named Executive Officers. The following elements of compensation, and EPCO's decisions with respect to determination of payments, are not subject to approvals by our Board or the ACG Committee of our general partner. Equity awards under EPCO's long-term incentive plans are approved by the ACG Committee of the respective issuer. We do not have a separate compensation committee.

As discussed below, the elements of EPCO's compensation program, along with EPCO's other rewards (e.g., benefits, work environment, career development), are intended to provide a total rewards package to employees. The compensation package is designed to reward contributions by employees in support of the business strategies of EPCO and its affiliates at both the partnership and individual levels. With respect to the three years ended December 31, 2008, EPCO's compensation package for Named Executive Officers did not include any elements based on targeted performance-related criteria.

The primary elements of EPCO's compensation program are a combination of annual cash and long-term equity-based incentive compensation. For the three years ended December 31, 2008, the elements of compensation for the Named Executive Officers consisted of the following:

- Annual base salary;
- Discretionary annual cash awards;
- Awards under long-term incentive arrangements; and
- Other compensation, including very limited perquisites.

In order to assist Mr. Duncan and EPCO with compensation decisions, our CEO and the senior vice president of Human Resources for EPCO formulate preliminary compensation recommendations for all of the Named Executive Officers other than our CEO. Mr. Duncan, after consulting with the senior vice president of Human Resources for EPCO, independently makes compensation decisions with respect to our Named Executive Officers. In making these compensation decisions, EPCO considers market data for determining relevant compensation levels and compensation program elements through the review of and, in certain cases, participation in, relevant compensation surveys and reports. These surveys and reports are conducted and prepared by a third party compensation consultant.

Periodically, EPCO will engage a third party consultant to review compensation elements provided to our executive officers. In 2006, EPCO engaged Towers Perrin to review executive compensation relative to our industry. Towers Perrin provided comparative market data on compensation practices and programs for executive level positions based on an analysis of industry competitors. Neither we nor EPCO, which engages the consultant, are aware of the identity of the component companies who supply data to the consultant. EPCO uses the data provided in the Towers Perrin analysis to gauge whether compensation levels reported by the consultant are within the general ranges of compensation for EPCO employees in similar positions, but that comparison is only a factor taken into consideration and may or may not impact compensation of our executive officers, for which Dan L. Duncan has the ultimate decision-making authority. EPCO does not otherwise engage in benchmarking executive level positions.

Mr. Duncan and EPCO do not use any formula or specific performance-based criteria for our Named Executive Officers in connection with determining compensation for services performed for us; rather, Mr. Duncan and EPCO determine an appropriate level and mix of compensation on a case-by-case basis. Further, there is no established policy or target for the allocation between either cash and non-cash or short-term and long-term incentive compensation. However, some considerations that Mr. Duncan may take into account in making the case-by-case compensation determinations include total value of wealth accumulated and the appropriate balance of internal pay equity among executive officers. Mr. Duncan and EPCO also consider individual performance, levels of responsibility, skills and experience. All compensation determinations are discretionary and, as noted above, subject to Mr. Duncan's ultimate decision-making authority except for equity awards under EPCO's long-term incentive plans, as discussed below.

We believe the absence of specific performance-based criteria associated with our salary compensation and equity awards, and the long-term nature of our equity awards, has the effect of not encouraging excessive risk taking by our executive officers in order to reach certain targets. Further, the practice of making compensation decisions on a case-by-case basis permits consideration of flexible criteria, including current overall market conditions. Because our 2008 annual base salaries and the majority of our 2008 equity awards were made in the first half of 2008, recent market volatility and market declines did not have a material impact on 2008 compensation decisions. However, current market conditions may impact 2009 compensation decisions regarding annual base salaries and equity award grants.

The discretionary cash awards paid to each of our Named Executive Officers were determined by consultation among Mr. Duncan, our CEO and the senior vice president of Human Resources for EPCO, subject to Mr. Duncan's final determination. These cash awards, in combination with annual base salaries, are intended to yield competitive total cash compensation levels for the Named Executive Officers and drive performance in support of our business strategies, as well as the performance of other EPCO affiliates for which the Named Executive Officers perform services. It is EPCO's general policy to pay these awards in February of each year.

The incentive awards granted under EPCO's long-term incentive plans to our Named Executive Officers were determined by consultation among Mr. Duncan, our CEO and the senior vice president of Human Resources for EPCO. Incentive awards issued under EPCO's long-term incentive plans involving our securities are also approved by the ACG Committee of our general partner. In addition, our Named Executive Officers are Class B limited partners in certain of the Employee Partnerships. Mr. Duncan approves the issuance of all limited partnership interests in the Employee Partnerships to our Named Executive Officers. See "Summary of Long-Term Incentive Arrangements Underlying 2008 Award Grants" within this Item 11 for information regarding the long-term incentive plans. See Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding the accounting for such awards.

EPCO generally does not pay for perquisites for any of our Named Executive Officers, other than reimbursement of certain parking expenses, and expects to continue its policy of covering very limited perquisites allocable to our Named Executive Officers. EPCO also makes matching contributions under its 401(k) plan for the benefit of our Named Executive Officers in the same manner as it does for other EPCO employees.

EPCO does not offer our Named Executive Officers a defined benefit pension plan. Also, none of our Named Executive Officers had nonqualified deferred compensation during the three years ended December 31, 2008.

We believe that each of the base salary, cash awards, and incentive awards fit the overall compensation objectives of us and of EPCO, as stated above (i.e., to provide competitive compensation opportunities to align and drive employee performance toward the creation of sustained long-term unitholder value, which will also allow us to attract, motivate and retain high quality talent with the skills and competencies required by us).

Compensation Committee Report

We do not have a separate compensation committee. In addition, we do not directly employ or compensate our Named Executive Officers. Rather, under the ASA with EPCO, we reimburse EPCO for the compensation of our executive officers. Accordingly, to the extent that decisions are made regarding the compensation policies pursuant to which our Named Executive Officers are compensated, they are made by Mr. Duncan and EPCO alone (except for equity awards, as previously noted), and not by our Board.

In light of the foregoing, the Board has reviewed and discussed the Compensation Discussion and Analysis with management and determined that the Compensation Discussion and Analysis be included in the Company's annual report on Form 10-K for the year ended December 31, 2008.

Submitted by: Dan L. Duncan
Michael A. Creel
W. Randall Fowler
Richard H. Bachmann
Dr. Ralph S. Cunningham
E. William Barnett
Charles M. Rampacek
Rex C. Ross
A.J. Teague

Notwithstanding anything to the contrary set forth in any previous filings under the Securities Act, as amended, or the Exchange Act, as amended, that incorporate future filings, including this annual report, in whole or in part, the foregoing report shall not be incorporated by reference into any such filings.

Grants of Plan-Based Awards in Fiscal Year 2008

The following table presents information concerning grants of plan-based awards to the Named Executive Officers in 2008. The restricted unit and unit option awards granted during 2008 were under the EPCO 1998 Plan and EPD 2008 LTIP.

Name	Grant Date	Estimated Future Payouts Under Equity Incentive Plan Awards Threshold (#)	Target (#)	Maximum (#)	Exercise or Base Price of Option Awards ($/Unit)	Grant Date Fair Value of Unit and Option Awards ($) (1)
Restricted unit awards: (2)						
Michael A. Creel (CEO)	5/22/08	--	40,000	--	--	$989,760
W. Randall Fowler (CFO)	5/22/08	--	28,100	--	--	$325,925
A.J. Teague	5/22/08	--	28,100	--	--	$869,133
James H. Lytal	5/22/08	--	28,100	--	--	$869,133
Richard H. Bachmann	5/22/08	--	28,100	--	--	$478,023
Unit option awards: (3)						
Michael A. Creel (CEO)	5/22/08	--	90,000	--	$30.93	$171,360
W. Randall Fowler (CFO)	5/22/08	--	60,000	--	$30.93	$53,550
A.J. Teague	5/22/08	--	60,000	--	$30.93	$142,800
James H. Lytal	5/22/08	--	60,000	--	$30.93	$142,800
Richard H. Bachmann	5/22/08	--	60,000	--	$30.93	$78,540
Profits interest awards: (4)						
Enterprise Unit:						
Michael A. Creel (CEO)	2/20/08	--	--	--	--	$586,622
W. Randall Fowler (CFO)	2/20/08	--	--	--	--	$121,198
A.J. Teague	2/20/08	--	--	--	--	$407,143
James H. Lytal	2/20/08	--	--	--	--	$162,857
Richard H. Bachmann	2/20/08	--	--	--	--	$223,929
EPCO Unit:						
Michael A. Creel (CEO)	11/13/08	--	--	--	--	$1,119,899
W. Randall Fowler (CFO)	11/13/08	--	--	--	--	$524,953
A.J. Teague	11/13/08	--	--	--	--	$1,399,873
James H. Lytal	11/13/08	--	--	--	--	--
Richard H. Bachmann	11/13/08	--	--	--	--	$769,930

(1) Amounts presented reflect that portion of grant date fair value allocable to us based on the percentage of time each Named Executive Officer spent on our consolidated business activities during 2008. Based on current allocations, we estimate that the consolidated compensation expense we record for each Named Executive Officer with respect to these awards will equal these amounts over time.
(2) For the period in which the restricted unit awards were outstanding during 2008, we recognized a total of $0.5 million of consolidated compensation expense related to these awards. The remaining portion of grant date fair value will be recognized as expense in future periods.
(3) For the period in which the unit option awards were outstanding during 2008, we recognized a total of $0.1 million of consolidated compensation expense related to these awards. The remaining portion of grant date fair value will be recognized as expense in future periods.
(4) For the period in which the profits interest awards were outstanding during 2008, we recognized a total of $0.3 million of consolidated compensation expense related to these awards. The remaining portion of grant date fair value will be recognized as expense in future periods.

The fair value amounts presented in the table are based on certain assumptions and considerations made by management. See Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding our fair value assumptions.

Summary of Long-Term Incentive Arrangements Underlying 2008 Award Grants

The following information summarizes the types of awards granted to our Named Executive Officers during the year ended December 31, 2008. For detailed information regarding our accounting for equity awards, see Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

As used in the context of the EPCO, the term "restricted unit" represents a time-vested unit under SFAS 123(R). Such awards are non-vested until the required service period expires.

EPCO 1998 Plan. The EPCO 1998 Plan provides for incentive awards to EPCO's key employees who perform management, administrative or operational functions for us or our affiliates. Awards granted under the EPCO 1998 Plan may be in the form of unit options, restricted units, phantom units and distribution equivalent rights ("DERs").

When issued, the exercise price of each option grant is equivalent to the market price per unit of our common units on the date of grant. In general, options granted under the EPCO 1998 Plan have a vesting period of four years and remain exercisable for ten years from the date of grant.

A total of 152,400 restricted units were granted under this plan to the Named Executive Officers in May 2008. Restricted unit awards under the EPCO 1998 Plan allow recipients to acquire our common units (at no cost to the recipient) once a defined vesting period expires, subject to certain forfeiture provisions. The restrictions on such awards generally lapse four years from the date of grant. The fair value of restricted units is based on the market price per unit of our common units on the date of grant less an allowance for estimated forfeitures. Each recipient is also entitled to cash distributions equal to the product of the number of restricted units outstanding for the participant and the cash distribution per unit paid by us to our unitholders.

The EPCO 1998 Plan also provides for the issuance of phantom unit awards, including related DERs. No phantom unit awards or associated DERs have been granted under the EPCO 1998 Plan.

EPD 2008 LTIP. The EPD 2008 LTIP provides for incentive awards to EPCO's key employees who perform management, administrative or operational functions for us or our affiliates. Awards granted under the EPD 2008 LTIP may be in the form of unit options, restricted units, phantom units and DERs.

A total of 330,000 options were granted under this plan to the Named Executive Officers in May 2008. When issued, the exercise price of each option grant was equivalent to the market price per unit of our common units on the date of grant. In general, these options have a vesting period of four years and are exercisable during specified periods within the calendar year immediately following the year in which vesting occurs. At December 31, 2008, no restricted units or DERs had been issued under this plan. There were a total of 4,400 phantom units granted under the EPD 2008 LTIP outstanding at December 31, 2008.

Profits interests awards. Our Named Executive Officers were granted awards consisting of profits interests, or Class B limited partner interests, in Enterprise Unit in February 2008 and EPCO Unit in November 2008. In addition, the Named Executive Officers have received profits interests awards in the other Employee Partnerships in prior years. Profits interest awards entitle each holder to participate in the expected long-term appreciation in value of the equity securities owned by each Employee Partnership. The Employee Partnerships in which the Named Executive Officers participate own either Enterprise GP Holdings units or our common units or a combination of both. Such awards are subject to forfeiture. For additional information regarding the Employee Partnerships, including the assumptions we used to estimate the fair value of these awards, see Note 5 of the Notes to Financial Statements included under Item 8 of this annual report.

The following table presents each Named Executive Officer's share of the total profits interest in the Employee Partnerships at December 31, 2008:

	Percentage Ownership of Class B Interests			
Named Executive Officer	**EPE Unit I**	**EPE Unit III**	**Enterprise Unit**	**EPCO Unit**
Michael A. Creel (CEO)	8.2%	7.8%	17.5%	20.0%
W. Randall Fowler (CFO)	5.5%	7.8%	7.8%	20.0%
A.J. Teague	5.5%	6.5%	9.7%	20.0%
James H. Lytal	5.5%	6.5%	3.9%	--
Richard H. Bachmann	8.2%	7.8%	9.7%	20.0%

Equity Awards Outstanding at December 31, 2008

The following tables present information concerning each Named Executive Officer's long-term incentive awards outstanding at December 31, 2008. We expect to be allocated our pro rata share of the cost of such awards under the ASA. As a result, the gross amounts listed in the table do not represent the amount of expense we will recognize in connection with these awards.

The following table presents information concerning each Named Executive Officer's nonvested restricted units and unexercised unit options at December 31, 2008:

		Option Awards			Unit Awards	
Name	**Vesting Date**	**Number of Units Underlying Options Unexercisable (#)**	**Option Exercise Price ($/Unit)**	**Option Expiration Date**	**Number of Units That Have Not Vested (#)(2)**	**Market Value of Units That Have Not Vested ($)(3)**
Restricted unit awards:						
Michael A. Creel (CEO)	Various (1)	--	--	--	88,500	$1,834,605
W. Randall Fowler (CFO)	Various (1)	--	--	--	63,100	$1,308,063
A.J. Teague	Various (1)	--	--	--	76,600	$1,587,918
James H. Lytal	Various (1)	--	--	--	76,600	$1,587,918
Richard H. Bachmann	Various (1)	--	--	--	76,600	$1,587,918
Unit option awards:						
Michael A. Creel (CEO):						
May 10, 2004 option grant	5/10/08	35,000	20.00	5/10/14	--	--
August 4, 2005 option grant	8/04/09	35,000	26.47	8/04/15	--	--
May 1, 2006 option grant	5/01/10	40,000	24.85	5/01/16	--	--
May 29, 2007 option grant	5/29/11	60,000	30.96	5/29/17	--	--
May 22, 2008 option grant	5/22/12	90,000	30.93	12/31/13	--	--
W. Randall Fowler (CFO):						
May 10, 2004 option grant	5/10/08	10,000	20.00	5/10/14	--	--
August 4, 2005 option grant	8/04/09	25,000	26.47	8/04/15	--	--
May 1, 2006 option grant	5/01/10	40,000	24.85	5/01/16	--	--
May 29, 2007 option grant	5/29/11	45,000	30.96	5/29/17	--	--
May 22, 2008 option grant	5/22/12	60,000	30.93	12/31/13	--	--
A.J. Teague:						
May 10, 2004 option grant	5/10/08	35,000	20.00	5/10/14	--	--
August 4, 2005 option grant	8/04/09	35,000	26.47	8/04/15	--	--
May 1, 2006 option grant	5/01/10	40,000	24.85	5/01/16	--	--
May 29, 2007 option grant	5/29/11	60,000	30.96	5/29/17	--	--
May 22, 2008 option grant	5/22/12	60,000	30.93	12/31/13	--	--
James H. Lytal:						
September 30, 2004 option grant	9/30/08	35,000	23.18	9/30/14	--	--
August 4, 2005 option grant	8/04/09	35,000	26.47	8/04/15	--	--
May 1, 2006 option grant	5/01/10	40,000	24.85	5/01/16	--	--
May 29, 2007 option grant	5/29/11	60,000	30.96	5/29/17	--	--
May 22, 2008 option grant	5/22/12	60,000	30.93	12/31/13	--	--
Richard H. Bachmann:						
May 10, 2004 option grant	5/10/08	35,000	20.00	5/10/14	--	--
August 4, 2005 option grant	8/04/09	35,000	26.47	8/04/15	--	--
May 1, 2006 option grant	5/01/10	40,000	24.85	5/01/16	--	--
May 29, 2007 option grant	5/29/11	60,000	30.96	5/29/17	--	--
May 22, 2008 option grant	5/22/12	60,000	30.93	12/31/13	--	--

(1) Of the 381,400 restricted unit awards presented in the table, 46,000 vest in 2009, 60,000 vest in 2010, 123,000 vest in 2011 and 152,400 vest in 2012.
(2) Amounts represent total number of restricted unit awards granted to Named Executive Officer.
(3) Amounts derived by multiplying the total number of restricted unit awards granted to the Named Executive Officer by the closing price of our common units at December 31, 2008 of $20.73 per unit.

The following table presents information concerning each Named Executive Officer's nonvested profits interest awards at December 31, 2008:

Name	Vesting Date	Option Awards: Number of Units Underlying Options Unexercisable (#)	Option Awards: Option Exercise Price ($/Unit)	Option Awards: Option Expiration Date	Unit Awards: Number of Units That Have Not Vested (#)	Unit Awards: Market Value of Units That Have Not Vested ($)
EPE Unit I:						
Michael A. Creel (CEO)	11/09/12	--	--	--	--	$ 0
W. Randall Fowler (CFO)	11/09/12	--	--	--	--	$ 0
A.J. Teague	11/09/12	--	--	--	--	$ 0
James H. Lytal	11/09/12	--	--	--	--	$ 0
Richard H. Bachmann	11/09/12	--	--	--	--	$ 0
EPE Unit III:						
Michael A. Creel (CEO)	5/09/14	--	--	--	--	$ 0
W. Randall Fowler (CFO)	5/09/14	--	--	--	--	$ 0
A.J. Teague	5/09/14	--	--	--	--	$ 0
James H. Lytal	5/09/14	--	--	--	--	$ 0
Richard H. Bachmann	5/09/14	--	--	--	--	$ 0
Enterprise Unit:						
Michael A. Creel (CEO)	2/20/14	--	--	--	--	$ 0
W. Randall Fowler (CFO)	2/20/14	--	--	--	--	$ 0
A.J. Teague	2/20/14	--	--	--	--	$ 0
James H. Lytal	2/20/14	--	--	--	--	$ 0
Richard H. Bachmann	2/20/14	--	--	--	--	$ 0
EPCO Unit:						
Michael A. Creel (CEO)	11/13/13	--	--	--	--	$ 0
W. Randall Fowler (CFO)	11/13/13	--	--	--	--	$ 0
A.J. Teague	11/13/13	--	--	--	--	$ 0
James H. Lytal	11/13/13	--	--	--	--	$ 0
Richard H. Bachmann	11/13/13	--	--	--	--	$ 0

The profits interest awards had no market (or assumed liquidation) value at December 31, 2008 due to a decrease in the market value of the limited partner interests owned by each Employee Partnership since the formation

Option Exercises and Stock Vested Table

The following table presents the exercise of unit options by and vesting of restricted units to our Named Executive Officers during the year ended December 31, 2008 for which we were historically responsible for a share of the related cost of such awards.

Name	Option Awards: Number of Units Acquired on Exercise (#)	Option Awards: Value Realized on Exercise ($)	Unit Awards: Number of Units Acquired on Vesting (#)	Unit Awards: Gross Value Realized on Vesting ($) (1)
Michael A. Creel (CEO)	--	--	54,553	$1,146,990
W. Randall Fowler (CFO)	--	--	23,777	$467,209
A.J. Teague	--	--	12,000	$364,440
James H. Lytal	--	--	37,532	$1,084,647
Richard H. Bachmann	--	--	54,553	$1,146,990

(1) Amount determined by multiplying the number of restricted unit awards that vested during 2008 by the closing price of our common units on the date of vesting.

No options were exercised by the Named Executive Officers during 2008.

Nonqualified Deferred Compensation for the 2008 Fiscal Year

During 2008, no Named Executive Officer received deferred compensation (other than incentive awards described elsewhere) on a basis that was not tax-qualified with respect to any defined contribution or other plan.

Director Compensation

The following table presents information regarding compensation to the independent directors of our general partner during 2008.

Name	Fees Earned or Paid in Cash ($)	Unit Awards ($)	Unit Appreciation Rights ($) (1)	Total ($)
E. William Barnett	$90,000	--	$ (3,886)	$86,114
Rex C. Ross	$75,000	--	(2,859)	$72,141
Charles M. Rampacek	$75,000	--	(2,859)	$72,141

(1) Amounts presented reflect compensation expense recognized in accordance with SFAS 123(R) by EPGP. Expense credits were recognized in 2008 as a result of a decrease in the price of Enterprise GP Holdings' units during the period.

Neither we nor EPGP provide any additional compensation to employees of EPCO who serve as directors of EPGP. The employees of EPCO who served as directors of EPGP during 2008 were Messrs. Duncan, Creel, Fowler, Bachmann, Cunningham and Teague.

Currently, EPGP's three independent directors, Messrs. Barnett, Ross and Rampacek, are provided cash compensation for their services as follows:

- Each independent director receives $75,000 in cash annually. Prior to August 2007, the annual retainer was $50,000 in cash and $25,000 worth of restricted units.

- If the individual serves as chairman of a committee of the Board of Directors, then he receives an additional $15,000 in cash annually.

The independent directors of our general partner have also received equity-based compensation in the form of Unit Appreciation Rights ("UARs"). These awards consist of letter agreements with each of the independent directors and are not part of any long-term incentive plan of the EPCO group of companies. The awards are based upon an incentive plan of EPE Holdings, and are made in the form of UAR grants for non-employee directors. The compensation expense associated with these awards is recognized by EPGP. These UARs entitle the independent directors to receive a cash amount in the future equal to the excess, if any, of the fair market value of Enterprise GP Holdings' units (determined as of a future vesting date) over the grant date price of such units. If a director resigns or is removed prior to vesting, his UAR awards are forfeited.

In August 2006, Mr. Barnett was granted 10,000 UARs under the letter agreement format. The grant date price of these rights was $35.71 per unit. These awards vest in August 2011 or on the date of certain qualifying events (as set forth in the form of grant). At December 31, 2008, the estimated fair value of these 10,000 UARs was $2 thousand. In November 2006, Mr. Barnett was issued an additional 20,000 UARs and Mr. Ross and Mr. Rampacek were each granted 30,000 UARs under the letter agreement format. The grant date price of these UARs was $34.10 per unit. These awards vest in November 2011 or on the date of certain qualifying events (as set forth in the form of grant). At December 31, 2008, the total fair value of these 80,000 UARs was $28 thousand. Our estimates of the fair values of the UARs were based on the following assumptions: (i) remaining life of awards of three years; (ii) risk-free interest rate of 1.0%; (iii) an expected distribution yield on Enterprise GP Holdings' units of 5.4%; and (iv) an expected unit price volatility of Enterprise GP Holdings' units of 30.3%.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters.***

Security Ownership of Certain Beneficial Owners

The following table sets forth certain information as of February 2, 2009, regarding each person known by our general partner to beneficially own more than 5.0% of our common units.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common units	Dan L. Duncan 1100 Louisiana Street, 10th Floor Houston, Texas 77002	152,506,527 (1)	33.8%

(1) For a detailed listing of ownership amounts that comprise Mr. Duncan's total beneficial ownership of our common units, see the table presented in the following section, "Security Ownership of Management," within this Item 12.

Security Ownership of Management

Enterprise Products Partners L.P. and Enterprise GP Holdings L.P.

The following sets forth certain information regarding the beneficial ownership of our common units and the units of Enterprise GP Holdings L.P. as of February 2, 2009 by:

- our Named Executive Officers;
- the current Directors of EPGP; and
- the current directors and executive officers of EPGP as a group.

If an individual does not own any securities in the foregoing registrants, he is not listed in the following table.

Enterprise GP Holdings owns 100.0% of the membership interests of EPGP. All information with respect to beneficial ownership has been furnished by the respective directors or officers. Each person has sole voting and dispositive power over the securities shown unless otherwise indicated below. The beneficial ownership amounts of certain individuals include options to acquire our common units that are exercisable within 60 days of the filing date of this annual report.

Mr. Duncan owns 50.4% of the voting stock of EPCO and, accordingly, exercises sole voting and dispositive power with respect to our common units beneficially owned by EPCO and its affiliates. The remaining shares of EPCO capital stock are owned primarily by trusts for the benefit of members of Mr. Duncan's family. The address of EPCO is 1100 Louisiana Street, 10th Floor, Houston, Texas 77002.

Name of Beneficial Owner	Enterprise Products Partners L.P. Common Units: Amount and Nature of Beneficial Ownership	Enterprise Products Partners L.P. Common Units: Percent of Class	Enterprise GP Holdings L.P. Units: Amount and Nature of Beneficial Ownership	Enterprise GP Holdings L.P. Units: Percent of Class
Dan L. Duncan:				
Units owned by EPCO:				
Through DFI Delaware Holdings, L.P.	121,990,717	27.0%	--	--
Through Duncan Family Interests, Inc.	--	--	71,860,405	51.6%
Through DFI GP Holdings L.P.	--	--	25,162,804	18.1%
Through Enterprise GP Holdings L.P.	13,670,925	3.0%	--	--
Through EPCO Holdings, Inc.	1,037,037	*	--	--
Units owned by DD Securities LLC	487,100	*	3,745,673	2.7%
Units owned by Employee Partnerships (1)	1,623,654	*	7,165,315	5.1%
Units owned by family trusts (2)	12,517,338	2.8%	243,071	*
Units owned directly	1,179,756	*	110,700	*
Total for Dan L. Duncan	152,506,527	33.8%	108,287,968	77.8%
Michael A. Creel (3)	195,842	*	35,000	*
W. Randall Fowler (3)	105,300	*	3,000	*
Richard H. Bachmann (3)	190,822	*	18,968	*
A.J. Teague (3)	260,442	*	17,000	*
Dr. Ralph S. Cunningham	76,847	*	4,000	*
E. William Barnett	2,154	*	--	*
Rex C. Ross	54,875	*	7,448	*
Charles M. Rampacek	9,615	*	--	*
All current directors and executive officers of EPGP, as a group, (14 individuals in total) (4)	153,677,694	34.0%	108,381,604	77.9%

** The beneficial ownership of each individual is less than 1.0% of the registrant's common units outstanding.*

(1) As a result of EPCO's ownership of the general partners of the Employee Partnerships, Mr. Duncan is deemed beneficial owner of the limited partner interests held by these entities.
(2) Mr. Duncan is deemed beneficial owner of the limited partner interests held by certain family trusts, the beneficiaries of which are shareholders of EPCO.
(3) These individuals are Named Executive Officers.
(4) Cumulatively, this group's beneficial ownership amount includes 150,000 options to acquire our common units that were issued under the EPCO 1998 Plan. These options vested in prior periods and remain exercisable within 60 days of the filing date of this annual report.

Essentially all of the ownership interests in us and Enterprise GP Holdings that are owned or controlled by EPCO are pledged as security under the credit facility of an EPCO affiliate. This credit facility contains customary and other events of default relating to EPCO and certain of its affiliates, including Enterprise GP Holdings, TEPPCO and us. In the event of a default under this credit facility, a change in control of Enterprise GP Holdings or us could occur, including a change in control of our respective general partners.

Duncan Energy Partners L.P.

Certain of our directors and executive officers purchased common units of Duncan Energy Partners in this offering. The following table presents the beneficial ownership of common units of Duncan Energy Partners by our directors, Named Executive Officers and all directors and officers of our general partner (as a group) at February 2, 2009.

Name of Beneficial Owner	Duncan Energy Partners L.P. Common Units: Amount and Nature of Beneficial Ownership	Percent of Class
Dan L. Duncan:		
Units owned by EPO (1)	42,726,987	74.1%
Units owned by DD Securities LLC	103,100	*
Units owned directly	282,500	*
Total for Dan L. Duncan	43,112,587	74.7%
Richard H. Bachmann (2,3)	10,171	*
W. Randall Fowler (3,4)	2,000	*
Michael A. Creel (3)	7,500	*
A.J. Teague (3)	6,000	*
Rex C. Ross	3,800	*
All current directors and executive officers of EPGP, as a group (14 individuals in total)	43,163,808	74.8%

** The beneficial ownership of each individual is less than 1.0% of the registrant's units outstanding.*

(1) Amount includes 37,333,887 Class B units of Duncan Energy Partners L.P. that converted to common units on a one-for-one basis on February 1, 2009. EPO was issued the Class B units as partial consideration for a December 2008 asset dropdown transaction with Duncan Energy Partners.

(2) Mr. Bachmann is the Chief Executive Officer of Duncan Energy Partners.

(3) These individuals are Named Executive Officers.

(4) Mr. Fowler is the Chief Financial Officer of Duncan Energy Partners.

The preceding tables do not present any beneficial ownership information for James H. Lytal, who was one of our Named Executive Officers for 2008. Mr. Lytal resigned from EPCO in January 2009.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth certain information as of December 31, 2008 regarding the long-term incentive plans of EPCO under which our common units are authorized for issuance.

Plan Category	Number of units to be issued upon exercise of outstanding common unit options	Weighted-average exercise price of outstanding common unit options	Number of units remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)
	(a)	(b)	(c)
Equity compensation plans approved by unitholders:			
EPCO 1998 Plan (1)	2,168,500	$26.32	814,674
EPD 2008 LTIP (2)	795,000	$30.93	9,205,000
Equity compensation plans not approved by unitholders:			
None	--	--	--
Total for equity compensation plans	2,963,500	$27.56	10,019,674

(1) Of the 2,168,500 unit options outstanding at December 31, 2008, 548,500 were immediately exercisable and an additional 365,000, 480,000 and 775,000 options are exercisable in 2009, 2010 and 2012, respectively.
(2) The 795,000 unit options outstanding at December 31, 2008 are exercisable in 2013.

EPCO 1998 Plan

The EPCO 1998 Plan is effective until either all available common units under the plan have been issued to participants or the earlier termination of the EPCO 1998 Plan by EPCO. The EPCO 1998 Plan also provides for the issuance of restricted common units, of which 2,080,600 were outstanding at December 31, 2008. During 2008, a total of 766,200 restricted unit awards were issued to key employees of EPCO and our independent directors.

EPD 2008 LTIP

On January 29, 2008, our unitholders approved the EPD 2008 LTIP, which provides for awards of our common units and other rights to our non-employee directors and to consultants and employees of EPCO and its affiliates providing services to us. Awards under the EPD 2008 LTIP may be granted in the form of unit options, restricted units, phantom units, UARs and DERs. The EPD 2008 LTIP is administered by the ACG Committee of our general partner. The EPD 2008 LTIP provides for the issuance of up to 10,000,000 of our common units. After giving effect to option awards outstanding at December 31, 2008, a total of 9,205,000 additional common units could be issued under the EPD 2008 LTIP.

The EPD 2008 LTIP may be amended or terminated at any time by the Board of Directors of EPCO or ACG Committee of our general partner; however, the rules of the NYSE require that any material amendment, such as a significant increase in the number of common units available under the plan or a change in the types of awards available under the plan, would require the approval of our unitholders. The ACG Committee is also authorized to make adjustments in the terms and conditions of, and the criteria included in, awards under the plan in specified circumstances. The EPD 2008 LTIP is effective until the earlier of January 29, 2018 or the time which all available units under the incentive plan have been delivered to participants or the time of termination of the plan by EPCO or the ACG Committee of our general partner.

For additional information regarding the EPCO 1998 Plan and EPD 2008 LTIP, see Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Item 13. *Certain Relationships and Related Transactions, and Director Independence*.

Certain Relationships and Related Transactions

The following information summarizes our business relationships and transactions with related parties during the year ended December 31, 2008. We believe that the terms and provisions of our related party agreements are fair to us; however, such agreements and transactions may not be as favorable to us as we could have obtained from unaffiliated third parties. For additional information regarding our related party transactions, see Note 17 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Relationship with EPCO and affiliates

We have an extensive and ongoing relationship with EPCO and its affiliates, which include the following significant entities that are not a part of our consolidated group of companies:

- EPCO and its private company subsidiaries;
- EPGP, our sole general partner;
- Enterprise GP Holdings, which owns and controls our general partner;
- TEPPCO, which is owned and controlled by Enterprise GP Holdings; and
- the Employee Partnerships.

We also have an ongoing relationship with Duncan Energy Partners, the financial statements of which are consolidated with those of our own. Our transactions with Duncan Energy Partners are eliminated in consolidation.

EPCO is a private company controlled by Dan L. Duncan, who is also a Director and Chairman of EPGP, our general partner. At December 31, 2008, EPCO and its affiliates beneficially owned 152,506,527 (or 34.5%) of our outstanding common units, which includes 13,670,925 of our common units owned by Enterprise GP Holdings. In addition, at December 31, 2008, EPCO and its affiliates beneficially owned 77.8% of the limited partner interests of Enterprise GP Holdings and 100.0% of its general partner, EPE Holdings. Enterprise GP Holdings owns all of the membership interests of EPGP. The principal business activity of EPGP is to act as our managing partner. The executive officers and certain of the directors of EPGP and EPE Holdings are employees of EPCO.

As our general partner, EPGP received cash distributions of $144.1 million from us during the year ended December 31, 2008. This amount includes incentive distributions of $125.9 million.

We and EPGP are both separate legal entities apart from each other and apart from EPCO, Enterprise GP Holdings and their respective other affiliates, with assets and liabilities that are separate from those of EPCO, Enterprise GP Holdings and their respective other affiliates. EPCO and its private company affiliates depend on the cash distributions they receive from us, Enterprise GP Holdings and other investments to fund their other operations and to meet their debt obligations. EPCO and its private company affiliates received $405.2 million in cash distributions from us and Enterprise GP Holdings during the year ended December 31, 2008. Also, we issued $67.0 million in common units to EPCO and its private company affiliates under our DRIP during the year ended December 31, 2008.

The ownership interests in us that are owned or controlled by Enterprise GP Holdings are pledged as security under its credit facility. In addition, substantially all of the ownership interests in us that are owned or controlled by EPCO and its affiliates, other than those interests owned by Enterprise GP Holdings, Dan Duncan LLC and certain trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of a private company affiliate of EPCO. This credit facility contains customary and other events of default relating to EPCO and certain affiliates, including Enterprise GP Holdings, TEPPCO and us.

An affiliate of EPCO provides us trucking services for the transportation of NGLs and other products. For the year ended December 31, 2008, we paid this trucking affiliate $21.7 million for such services.

We lease office space in various buildings from affiliates of EPCO. The rental rates in these lease agreements approximate market rates. For the year ended December 31, 2008, we paid EPCO $5.3 million for office space leases.

Historically, we entered into transactions with a Canadian affiliate of EPCO for the purchase and sale of NGL products in the normal course of business. These transactions were at market-related prices. We acquired this affiliate in October 2006 and began consolidating its financial statements with those of our own from the date of acquisition. For the nine months ended September 30, 2006, our revenues from this former unconsolidated affiliate were $55.8 million and our purchases were $43.4 million.

EPCO ASA. We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to an ASA. We, Duncan Energy Partners, Enterprise GP Holdings, TEPPCO and our respective general partners are parties to the ASA. The significant terms of the ASA are as follows:

- EPCO will provide selling, general and administrative services, and management and operating services, as may be necessary to manage and operate our businesses, properties and assets (all in accordance with prudent industry practices). EPCO will employ or otherwise retain the services of such personnel as may be necessary to provide such services.

- We are required to reimburse EPCO for its services in an amount equal to the sum of all costs and expenses incurred by EPCO which are directly or indirectly related to our business or activities (including expenses reasonably allocated to us by EPCO). In addition, we have agreed to pay all sales, use, excise, value added or similar taxes, if any, that may be applicable from time to time in respect of the services provided to us by EPCO.

- EPCO will allow us to participate as a named insured in its overall insurance program, with the associated premiums and other costs being allocated to us.

Under the ASA, EPCO subleases to us (for $1 per year) certain equipment which it holds pursuant to operating leases and has assigned to us its purchase option under such leases (the "retained leases"). EPCO remains liable for the actual cash lease payments associated with these agreements. We record the full value of these payments made by EPCO on our behalf as a non-cash related party operating lease expense, with the offset to partners' equity accounted for as a general contribution to our partnership. We exercised our election under the retained leases to purchase a cogeneration unit in December 2008 for $2.3 million. Should we decide to exercise the purchase option associated with the remaining agreement, we would pay the original lessor $3.1 million in June 2016.

Our operating costs and expenses for the year ended December 31, 2008 include reimbursement payments to EPCO for the costs it incurs to operate our facilities, including compensation of employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets. Such reimbursements were $329.7 million during the year ended December 31, 2008.

Likewise, our general and administrative costs for the year ended December 31, 2008 include amounts we reimburse to EPCO for administrative services, including compensation of employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to ASA based on the estimated use of such services by each party (e.g., the allocation of general legal or accounting salaries based on estimates of time spent on each entity's business and affairs). Such reimbursements were $59.1 million during the year ended December 31, 2008.

Since the vast majority of such expenses are charged to us on an actual basis (i.e. no mark-up or subsidy is charged or received by EPCO), we believe that such expenses are representative of what the amounts would have been on a stand-alone basis. With respect to allocated costs, we believe that the proportional direct allocation method employed by EPCO is reasonable and reflective of the estimated level of costs we would have incurred on a stand-alone basis.

The ASA also addresses potential conflicts that may arise among Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), Duncan Energy Partners (including DEP GP), and the EPCO Group. The EPCO Group includes EPCO and its other affiliates, but excludes Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners and their respective general partners. With respect to potential conflicts, the ASA provides, among other things, that:

- If a business opportunity to acquire "equity securities" (as defined below) is presented to the EPCO Group, Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), Duncan Energy Partners (including DEP GP), then Enterprise GP Holdings will have the first right to pursue such opportunity. The term "equity securities" is defined to include:

  - general partner interests (or securities which have characteristics similar to general partner interests) or interests in "persons" that own or control such general partner or similar interests (collectively, "GP Interests") and securities convertible, exercisable, exchangeable or otherwise representing ownership or control of such GP Interests; and

  - incentive distribution rights and limited partner interests (or securities which have characteristics similar to incentive distribution rights or limited partner interests) in publicly traded partnerships or interests in "persons" that own or control such limited partner or similar interests (collectively, "non-GP Interests"); provided that such non-GP Interests are associated with GP Interests and are owned by the owners of GP Interests or their respective affiliates.

  Enterprise GP Holdings will be presumed to want to acquire the equity securities until such time as EPE Holdings advises the EPCO Group, EPGP and DEP GP that it has abandoned the pursuit of such business opportunity. In the event that the purchase price of the equity securities is reasonably likely to equal or exceed $100.0 million, the decision to decline the acquisition will be made by the chief executive officer of EPE Holdings after consultation with and subject to the approval of the ACG Committee of EPE Holdings. If the purchase price is reasonably likely to be less than $100.0 million, the chief executive officer of EPE Holdings may make the determination to decline the acquisition without consulting the ACG Committee of EPE Holdings.

  In the event that Enterprise GP Holdings abandons the acquisition and so notifies the EPCO Group, EPGP and DEP GP, Enterprise Products Partners will have the second right to pursue such acquisition. Enterprise Products Partners will be presumed to want to acquire the equity securities until such time as EPGP advises the EPCO Group and DEP GP that Enterprise Products Partners has abandoned the pursuit of such acquisition. In determining whether or not to pursue the acquisition, Enterprise Products Partners will follow the same procedures applicable to Enterprise GP Holdings, as described above but utilizing EPGP's chief executive officer and ACG Committee.

  In its sole discretion, Enterprise Products Partners may affirmatively direct such acquisition opportunity to Duncan Energy Partners. In the event this occurs, Duncan Energy Partners may pursue such acquisition.

  In the event Enterprise Products Partners abandons the acquisition opportunity for the equity securities and so notifies the EPCO Group and DEP GP, the EPCO Group may pursue the acquisition or offer the opportunity to TEPPCO (including TEPPCO GP) and their controlled affiliates, in either case, without any further obligation to any other party or offer such opportunity to other affiliates.

- If any business opportunity not covered by the preceding bullet point (i.e. not involving "equity securities") is presented to the EPCO Group, Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), or Duncan Energy Partners (including DEP GP), Enterprise Products Partners will have the first right to pursue such opportunity either for itself or, if desired by Enterprise Products Partners in its sole discretion, for the benefit of Duncan Energy Partners. It will be presumed that Enterprise Products Partners will pursue the business opportunity until such time as its general partner advises the EPCO Group, EPE Holdings and DEP GP that it has abandoned the pursuit of such business opportunity.

  In the event the purchase price or cost associated with the business opportunity is reasonably likely to equal or exceed $100.0 million, any decision to decline the business opportunity will be made by the chief executive officer of EPGP after consultation with and subject to the approval of the ACG Committee of EPGP. If the purchase price or cost is reasonably likely to be less than $100.0 million, the chief executive officer of EPGP may make the determination to decline the business opportunity without consulting EPGP's ACG Committee.

  In its sole discretion, Enterprise Products Partners may affirmatively direct such acquisition opportunity to Duncan Energy Partners. In the event this occurs, Duncan Energy Partners may pursue such acquisition.

  In the event that Enterprise Products Partners abandons the business opportunity for itself and Duncan Energy Partners and so notifies the EPCO Group, EPE Holdings and DEP GP, Enterprise GP Holdings will have the second right to pursue such business opportunity. It will be presumed that Enterprise GP Holdings will pursue such acquisition until such time as its general partner declines such opportunity (in accordance with the procedures described above for Enterprise Products Partners) and advises the EPCO Group that it has abandoned the pursuit of such business opportunity. Should this occur, the EPCO Group may either pursue the business opportunity or offer the business opportunity to TEPPCO (including TEPPCO GP) and their controlled affiliates without any further obligation to any other party or offer such opportunity to other affiliates.

None of Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners or their respective general partners or the EPCO Group have any obligation to present business opportunities to TEPPCO (including TEPPCO GP) or their controlled affiliates. Likewise, TEPPCO (including TEPPCO GP) and their controlled affiliates have no obligation to present business opportunities to Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners or their respective general partners or the EPCO Group.

The ASA was amended on January 30, 2009 to provide for the cash reimbursement by us and Enterprise GP Holdings to EPCO of distributions of cash or securities, if any, made by EPCO Unit to its Class B limited partners. The ASA amendment also extended the term under which EPCO provides services to the partnership entities from December 2010 to December 2013 and made other updating and conforming changes.

Employee Partnerships. EPCO formed the Employee Partnerships to serve as an incentive arrangement for key employees of EPCO by providing them a "profits interest" in such partnerships. Certain EPCO employees who work on behalf of us and EPCO were issued Class B limited partner interests and admitted as Class B limited partners without any capital contribution. The profits interest awards (i.e., the Class B limited partner interests) in the Employee Partnerships entitles each holder to participate in the appreciation in value of our common units, Enterprise GP Holdings' units, or both. For information regarding the Employee Partnerships, see Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Relationship with TEPPCO

TEPPCO became a related party to us in February 2005 when its general partner was acquired by private company affiliates of EPCO. Our relationship was further reinforced by the acquisition of TEPPCO's general partner by Enterprise GP Holdings in May 2007. Enterprise GP Holdings also owns our general partner.

We received $121.2 million from TEPPCO during the year ended December 31, 2008 from the sale of hydrocarbon products. We paid TEPPCO $42.0 million for NGL pipeline transportation and storage services during the year ended December 31, 2008.

Purchase of Pioneer I plant from TEPPCO. In March 2006, we paid TEPPCO $38.2 million for its Pioneer I natural gas processing plant located in Opal, Wyoming and certain natural gas processing rights related to natural gas production from the Jonah and Pinedale fields located in the Greater Green River Basin in Wyoming. After an in-depth consideration of all relevant factors, this transaction was approved by the ACG Committee of our general partner and the Audit and Conflicts Committee of the general partner of TEPPCO. TEPPCO has no continued involvement in the contracts or in the operations of the Pioneer facility.

Jonah Joint Venture with TEPPCO. In August 2006, we became a joint venture partner with TEPPCO in its Jonah Gas Gathering Company ("Jonah"), which owns the Jonah Gas Gathering System located in the Greater Green River Basin of southwestern Wyoming. The Jonah Gathering System gathers and transports natural gas produced from the Jonah and Pinedale fields to regional natural gas processing plants and major interstate pipelines that deliver natural gas to end-user markets.

Prior to entering into the Jonah joint venture, we managed the construction of the Phase V expansion and funded the initial construction costs under a letter of intent we entered into in February 2006. In connection with the joint venture arrangement, we and TEPPCO shared equally in the costs of the Phase V expansion, which increased the capacity of the Jonah Gathering System from 1.5 billion cubic feet per day ("Bcf/d") to 2.4 Bcf/d and significantly reduced system operating pressures, which we anticipate will lead to increased production rates and ultimate reserve recoveries. The first portion of the expansion, which has increased the system gathering capacity to 2.0 Bcf/d, was completed in July 2007 and the final phase of this expansion was completed in June 2008. We managed the Phase V construction project. Currently, the gathering capacity of this system is 2.4 Bcf/d.

Since August 1, 2006, we and TEPPCO have equally shared in the construction costs of the Phase V expansion. TEPPCO has reimbursed us $306.5 million, which represents 50.0% of total Phase V costs incurred through December 31, 2008. We had a receivable of $1.0 million from TEPPCO at December 31, 2008 for Phase V expansion costs.

During the first quarter of 2008, Jonah initiated a separate project to increase gathering capacity on that portion of its system that serves the Pinedale production field. This new project is expected to increase overall capacity of the Jonah Gas Gathering System by an additional 0.2 Bcf/d. The total anticipated cost of this new project is $125.0 million, of which we will be responsible for our share of the construction costs.

TEPPCO was entitled to all distributions from the joint venture until specified milestones were achieved, at which point, we became entitled to receive 50.0% of the incremental cash flow from portions of the system placed in-service as part of the expansion. Since the first phase of this expansion was reached in July 2007, we and TEPPCO have shared earnings based on a formula that takes into account our respective capital contributions, including expenditures by TEPPCO prior to the expansion.

At December 31, 2008, we owned an approximate 19.4% interest in Jonah and TEPPCO owns 80.6%. We operate the Jonah system. We account for our investment in the Jonah joint venture using the equity method.

The Jonah joint venture is governed by a management committee comprised of two representatives approved by us and two appointed by TEPPCO, each with equal voting power. After an in-depth consideration of all relevant factors, this transaction was approved by the ACG Committee of our general partner and the Audit and Conflicts Committee of the general partner of TEPPCO.

We have agreed to indemnify TEPPCO from any and all losses, claims, demands, suits, liabilities, costs and expenses arising out of or related to breaches of our representations, warranties, or covenants related to the Jonah joint venture. A claim for indemnification cannot be filed until the losses suffered by TEPPCO exceed $1.0 million. The maximum potential amount of future payments under the indemnity agreement is limited to $100.0 million. All indemnity payments are net of insurance recoveries that TEPPCO may receive from third-party insurance carriers. We carry insurance coverage that may offset any payments required under the indemnification.

Purchase of Houston-area pipelines from TEPPCO. In October 2006, we purchased certain idle pipeline assets in the Houston, Texas area from TEPPCO for $11.7 million in cash. The acquired pipelines became part of our Texas Intrastate System. The purchase of this asset was in accordance with the Board-approved management authorization policy.

Purchase and lease of pipelines for DEP South Texas NGL Pipeline System from TEPPCO. In January 2007, we purchased a 10-mile segment of pipeline from TEPPCO located in the Houston area for $8.0 million. This pipeline segment is part of the DEP South Texas NGL Pipeline System that commenced operations in January 2007. In addition, we entered into a lease with TEPPCO for an 11-mile interconnecting pipeline located in the Houston area that is part of the DEP South Texas NGL Pipeline System. Although the primary term of the lease expired in September 2007, it was renewed on a month-to-month basis until construction of a parallel pipeline was completed in early 2008. These transactions were in accordance with the Board-approved management authorization policy.

Texas Offshore Port System Joint Venture. In August 2008, we, together with TEPPCO and Oiltanking Holding Americas, Inc. ("Oiltanking"), announced the formation of the Texas Offshore Port System, a joint venture to design, construct, operate and own a Texas offshore crude oil port and a related onshore pipeline and storage system that would facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. The joint venture's primary project, referred to as "TOPS," includes (i) an offshore port (which will be located approximately 36 miles from Freeport, Texas), (ii) an onshore storage facility with approximately 3.9 million barrels of crude oil storage capacity, and (iii) an 85-mile crude oil pipeline system having a transportation capacity of up to 1.8 million barrels per day, that will extend from the offshore port to a storage facility near Texas City, Texas. The joint venture's complementary project, referred to as the Port Arthur Crude Oil Express (or "PACE") will transport crude oil from Texas City, including crude oil from TOPS, and will consist of a 75-mile pipeline and 1.2 million barrels of crude oil storage capacity in the Port Arthur, Texas area. The timing of the construction and related capital costs of the TOPS and PACE projects will be affected by the expansion plans of Motiva and the acquisition of requisite permits.

We, TEPPCO and Oiltanking each own, through our respective subsidiaries, a one-third interest in the joint venture. The aggregate cost of the TOPS and PACE projects is expected to be approximately $1.8 billion (excluding capitalized interest), with the majority of such capital expenditures currently expected to occur in 2010 and 2011. We and TEPPCO have each guaranteed up to approximately $700.0 million, which includes a contingency amount for potential cost overruns, of the capital contribution obligations of our respective subsidiary partners in the joint venture. As of December 31, 2008, our investment in the Texas Offshore Port System was $35.9 million.

Relationship with Energy Transfer Equity

Enterprise GP Holdings acquired equity method investments in Energy Transfer Equity and its general partner in May 2007. As a result, Energy Transfer Equity and its consolidated subsidiaries became related parties to our consolidated businesses.

For the year ended December 31, 2008, we recorded $618.4 million of revenues from Energy Transfer Partners, L.P. (“ETP”), primarily from NGL marketing activities. We incurred $192.2 million in costs of sales and operating costs and expenses for the year ended December 31, 2008. We have a long-term revenue generating contract with Titan Energy Partners, L.P. (“Titan”), a consolidated subsidiary of ETP. Titan purchases substantially all of its propane requirements from us. The contract continues until March 31, 2010 and contains renewal and extension options. We and Energy Transfer Company (“ETC OLP”) transport natural gas on each other’s systems and share operating expenses on certain pipelines. ETC OLP also sells natural gas to us.

Relationship with Duncan Energy Partners

Duncan Energy Partners was formed in September 2006 and did not acquire any assets prior to February 5, 2007, which was the date it completed its initial public offering of 14,950,000 common units and acquired controlling interests in certain midstream energy businesses of EPO. The business purpose of Duncan Energy Partners is to acquire, own and operate a diversified portfolio of midstream energy assets and to support the growth objectives of EPO and other affiliates under common control. Duncan Energy Partners is engaged in the business of transporting and storing NGLs and petrochemical products and gathering, transporting, storing and marketing of natural gas.

At December 31, 2008, Duncan Energy Partners is owned 99.3% by its limited partners and 0.7% by its general partner, DEP GP, which is a wholly owned subsidiary of EPO. DEP GP is responsible for managing the business and operations of Duncan Energy Partners. DEP Operating Partnership L.P. (“DEP OLP”), a wholly owned subsidiary of Duncan Energy Partners, conducts substantially all of Duncan Energy Partners’ business.

At December 31, 2008, EPO owned approximately 74.1% of Duncan Energy Partners’ limited partner interests and 100.0% of its general partner.

DEP I Midstream Businesses. On February 5, 2007, EPO contributed a 66.0% controlling equity interest in each of the DEP I Midstream Businesses (defined below) to Duncan Energy Partners in a dropdown of assets (the “DEP I dropdown”). EPO retained the remaining 34.0% equity interest in each of the DEP I Midstream Businesses. The DEP I Midstream Businesses consist of (i) Mont Belvieu Caverns, LLC (“Mont Belvieu Caverns”); (ii) Acadian Gas, LLC (“Acadian Gas”); (iii) Enterprise Lou-Tex Propylene Pipeline L.P. (“Lou-Tex Propylene”), including its general partner; (iv) Sabine Propylene Pipeline L.P. (“Sabine Propylene’), including its general partner; and (v) South Texas NGL Pipelines, LLC (“South Texas NGL”).

As consideration for controlling equity interests in the DEP I Midstream Businesses and reimbursement for capital expenditures related to these businesses, Duncan Energy Partners distributed to EPO (i) $260.6 million of the $290.5 million of net proceeds from its initial public offering to EPO, (ii) $198.9 million in borrowings under its revolving credit facility and (iii) a net 5,351,571 common units of Duncan Energy Partners. See Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding the debt obligations of Duncan Energy Partners.

DEP II Midstream Businesses. On December 8, 2008, Duncan Energy Partners entered into a Purchase and Sale Agreement (the “DEP II Purchase Agreement”) with EPO and Enterprise GTM Holdings L.P. (“Enterprise GTM,” a wholly owned subsidiary of EPO). Pursuant to the DEP II Purchase Agreement, DEP OLP acquired 100.0% of the membership interests in Enterprise Holding III, LLC (“Enterprise III”) from Enterprise GTM, thereby acquiring a 66.0% general partner interest in Enterprise GC, L.P. (“Enterprise GC”), a 51.0% general partner interest in Enterprise Intrastate L.P. (“Enterprise Intrastate”) and a 51.0% membership interest in Enterprise Texas Pipeline LLC (“Enterprise Texas”). Collectively, we refer to Enterprise GC, Enterprise Intrastate and Enterprise Texas as the “DEP II Midstream Businesses.” EPO was the sponsor of this second dropdown transaction (the “DEP II dropdown”). Enterprise GTM retained the remaining limited partner and member interests in the DEP II Midstream Businesses.

As consideration for controlling equity interests in the DEP II Midstream Businesses, EPO received $280.5 million in cash and 37,333,887 Class B limited partner units having a market value of $449.5 million from Duncan Energy Partners. The Class B limited partner units automatically converted to common units of Duncan Energy Partners on February 1, 2009. The total value of the consideration provided to EPO and Enterprise GTM was $730.0 million. The cash portion of the consideration provided by Duncan Energy Partners in this dropdown transaction was derived from borrowings under a term loan. See Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding the debt obligations of Duncan Energy Partners.

Generally, the DEP II dropdown transaction documents provide that to the extent that the DEP II Midstream Businesses generate cash sufficient to pay distributions to their partners or members, such cash will be distributed to Enterprise III (a wholly owned by Duncan Energy Partners) and Enterprise GTM (our wholly owned subsidiary) in an amount sufficient to generate an aggregate annualized return on their respective investments of 11.85%. Distributions in excess of this amount will be distributed 98.0% to Enterprise GTM and 2.0% to Enterprise III. The initial annual fixed return amount of 11.85% will be increased by 2.0% each calendar year beginning January 1, 2010. For example, the fixed return in 2010, assuming no other adjustments, would be 102% of 11.85%, or 12.087%.

Duncan Energy Partners paid a pro rated cash distribution of $0.1115 per unit on the Class B units with respect to the fourth quarter of 2008.

The borrowings of Duncan Energy Partners are presented as part of our consolidated debt; however, we do not have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

We may contribute other equity interests in our subsidiaries to Duncan Energy Partners and use the proceeds we receive from Duncan Energy Partners to fund our capital spending program.

Omnibus Agreement. On December 8, 2008, we entered into an amended and restated Omnibus Agreement with Duncan Energy Partners. The key provisions of this agreement are summarized as follows:

- indemnification for certain environmental liabilities, tax liabilities and right-of-way defects with respect to the DEP I and DEP II Midstream Businesses we contributed to Duncan Energy Partners in connection with the respective dropdown transactions;

- funding by EPO of 100.0% of post-February 5, 2007 capital expenditures incurred by South Texas NGL and Mont Belvieu Caverns with respect to certain expansion projects under construction at the time of Duncan Energy Partners' initial public offering;

- funding by EPO of 100.0% of post-December 8, 2008 capital expenditures (estimated at $1.4 million) to complete the Sherman Extension natural gas pipeline;

- a right of first refusal to EPO in our current and future subsidiaries and a right of first refusal on the material assets of such subsidiaries, other than sales of inventory and other assets in the ordinary course of business; and

- a preemptive right with respect to equity securities issued by certain of our subsidiaries, other than as consideration in an acquisition or in connection with a loan or debt financing.

We and Duncan Energy Partners have also agreed to negotiate in good faith any necessary amendments to the partnership or company agreements of the DEP II Midstream Businesses when either party believes that business circumstances have changed.

Our general partner's ACG Committee must approve amendments to the Omnibus Agreement when such amendments would adversely affect our unitholders.

EPO has indemnified Duncan Energy Partners against certain environmental liabilities, tax liabilities and right-of-way defects associated with the assets EPO contributed to Duncan Energy Partners in connection with the DEP I and DEP II dropdown transactions. These liabilities include both known and unknown environmental and related liabilities. These indemnifications terminate on February 5, 2010. There is an aggregate cap of $15.0 million on the amount of indemnity coverage and Duncan Energy Partners is not entitled to indemnification until the aggregate amount of claims it incurs exceeds $250 thousand. Environmental liabilities resulting from a change of law after February 5, 2007 are excluded from the indemnity. In addition, EPO has indemnified Duncan Energy Partners for liabilities related to:

- certain defects in the easement rights or fee ownership interests in and to the lands on which any assets contributed to Duncan Energy Partners in connection with its initial public offering are located and failure to obtain certain consents and permits necessary to conduct its business that arise through February 5, 2010; and

- certain income tax liabilities attributable to the operation of the assets contributed to Duncan Energy Partners in connection with its initial public offering prior to February 5, 2007.

The Omnibus Agreement may not be amended without the prior approval of the ACG Committee if the proposed amendment will, in the reasonable discretion of DEP GP, adversely affect holders of its common units.

Neither we, nor EPO and any of its affiliates are restricted under the Omnibus Agreement from competing with Duncan Energy Partners. Except as otherwise expressly agreed in the EPCO ASA, EPO and any of its affiliates may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer Duncan Energy Partners the opportunity to purchase or construct those assets. These agreements are in addition to other agreements relating to business opportunities and potential conflicts of interest set forth in the ASA with EPO, EPCO and other affiliates of EPCO.

Under the Omnibus Agreement, EPO agreed to make additional contributions to Duncan Energy Partners as reimbursement for Duncan Energy Partners' 66.0% share of any excess construction costs above the (i) $28.6 million of estimated capital expenditures to complete the Phase II expansions of the DEP South Texas NGL Pipeline System and (ii) $14.1 million of estimated construction costs for additional brine production capacity and above-ground storage reservoir projects at Mont Belvieu, Texas. Both projects were underway at the time of Duncan Energy Partners' initial public offering. EPO made cash contributions to Duncan Energy Partners of $32.5 million and $9.9 million in connection with the Omnibus Agreement during the years ended December 31, 2008 and 2007, respectively. The majority of these contributions related to funding the Phase II expansion costs of the DEP South Texas NGL Pipeline System. EPO will not receive an increased allocation of earnings or cash flows as a result of these contributions to South Texas NGL and Mont Belvieu Caverns.

Mont Belvieu Caverns' LLC Agreement. The Mont Belvieu Caverns' LLC Agreement (the "Caverns LLC Agreement") states that if Duncan Energy Partners elects to not participate in certain projects of Mont Belvieu Caverns, then EPO is responsible for funding 100.0% of such projects. To the extent such non-participated projects generate identifiable incremental cash flows for Mont Belvieu Caverns in the future, the earnings and cash flows of Mont Belvieu Caverns will be adjusted to allocate such incremental amounts to EPO by special allocation or otherwise. Under the terms of the Caverns LLC Agreement, Duncan Energy Partners may elect to acquire a 66.0% share of these projects from EPO within 90 days of such projects being placed in service.

EPO made cash contributions of $99.5 million and $38.1 million under the Caverns LLC Agreement during the years ended December 31, 2008 and 2007, respectively, to fund 100.0% of certain storage-related projects for the benefit of EPO's NGL marketing activities. At present, Mont Belvieu Caverns is not expected to generate any identifiable incremental cash flows in connection with these projects; thus, the sharing ratio for Mont Belvieu Caverns is not expected to change from the current sharing ratio of 66.0% for Duncan Energy Partners and 34.0% for EPO. EPO expects to make additional contributions of approximately $27.5 million to fund such projects in 2009. The constructed assets will be the property of Mont Belvieu Caverns.

In November 2008, the Caverns LLC Agreement was amended to provide that EPO would prospectively receive a special allocation of 100.0% of the depreciation related to projects that it has fully funded. For the two-month period in 2008 covered by the amendment, EPO was allocated depreciation expense of $1.0 million related to such projects.

The Caverns LLC Agreement also requires the allocation to EPO of operational measurement gains and losses. Operational measurement gains and losses are created when product is moved between storage wells and are attributable to pipeline and well connection measurement variances.

Company and Limited Partnership Agreements – DEP II Midstream Businesses. On December 8, 2007, the DEP II Midstream Businesses amended and restated their governing documents in connection with the DEP II dropdown transaction. Collectively, these amended and restated agreements provide for the following:

- the acquisition by Enterprise III (a wholly owned subsidiary of Duncan Energy Partners) from Enterprise GTM (our wholly owned subsidiary) of a 66.0% general partner interest in Enterprise GC, a 51.0% general partner interest in Enterprise Intrastate and a 51.0% member interest in Enterprise Texas;

- the payment of distributions in accordance with an overall “waterfall” approach that stipulates that to the extent that the DEP II Midstream Businesses collectively generate cash sufficient to pay distributions to their partners or members, such cash will be distributed first to Enterprise III (based on an initial defined investment of $730.0 million, the “Enterprise III Distribution Base”) and then to Enterprise GTM (based on an initial defined investment of $452.1 million, the “Enterprise GTM Distribution Base”) in amounts sufficient to generate an aggregate annualized fixed return on their respective investments of 11.85%. Distributions in excess of these amounts will be distributed 98.0% to Enterprise GTM and 2.0% to Enterprise III. The initial annual fixed return amount of 11.85% will be increased by 2.0% each calendar year beginning January 1, 2010. For example, the fixed return in 2010, assuming no other adjustments, would be 102% of 11.85%, or 12.087%;

- the funding of operating cash flow deficits in accordance with each owner’s respective partner or member interest; and

- the election by either owner to fund cash calls associated with expansion capital projects. Since December 8, 2008, Enterprise III has elected to not participate in such cash calls and, as a result, Enterprise GTM has funded 100.0% of the expansion project costs of the DEP II Midstream Businesses. If Enterprise III later elects to participate in an expansion projects, then Enterprise III will be required to make a capital contribution for its share of the project costs.

  Any capital contributions to fund expansion projects made by either Enterprise III or Enterprise GTM will increase such partner’s Distribution Base (and hence future priority return amounts) under the Company Agreement of Enterprise Texas. As noted, Enterprise III has declined participation in expansion project spending since December 8, 2008. As a result, Enterprise GTM has funded 100.0% of such growth capital spending and its Distribution Base has increased from $452.1 million at December 8, 2008 to $473.4 million at December 31, 2008. The Enterprise III Distribution Base was unchanged at $730.0 million at December 31, 2008.

Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates perform supporting or complementary roles to our other business operations. Since we and our affiliates hold ownership interests in these entities and directly or indirectly benefit from our related party transactions with such entities, they are presented here. The following information summarizes significant related party transactions with our current unconsolidated affiliates:

- We sell natural gas to Evangeline, which, in turn, uses the natural gas to satisfy supply commitments it has with a major Louisiana utility. Revenues from Evangeline were $362.9 million for the year ended December 31, 2008. In addition, Duncan Energy Partners furnished $1.0 million in letters of credit on behalf of Evangeline at December 31, 2008.

- We pay Promix for the transportation, storage and fractionation of NGLs. In addition, we sell natural gas to Promix for its plant fuel requirements. For the year ended December 31, 2008, we recorded revenues of $24.5 million from Promix and paid Promix $38.7 million for its services to us.

- We pay Jonah for natural gas purchases from its gathering system. Expenses with Jonah were $38.3 million and $4.9 million for the years ended December 31, 2008 and 2007. We were not entitled to our 19.4% interest in Jonah until July 2007.

- We perform management services for certain of our unconsolidated affiliates. We charged such affiliates $9.9 million for such services during the year ended December 31, 2008.

Review and Approval of Transactions with Related Parties

We generally consider transactions between us and our subsidiaries, on the one hand, and our executive officers and directors (or their immediate family members), our general partner or its affiliates (including companies owned or controlled by Mr. Duncan such as EPCO), on the other hand, to be related party transactions. As further described below, our partnership agreement sets forth procedures by which related party transactions and conflicts of interest may be approved or resolved by the general partner or the ACG Committee. In addition, our ACG Committee Charter, our general partner's written internal review and approval policies and procedures, or "management authorization policy," and the amended and restated ASA with EPCO govern specified related party transactions, as further described below.

The ACG Committee Charter provides that the ACG Committee is established to review and approve related party transactions:

- for which Board approval is required by our management authorization policy, as such policy may be amended from time to time;

- where an officer or director of the general partner or any of our subsidiaries is a party, without regard to the size of the transaction;

- when requested to do so by management or the Board; or

- pursuant to our partnership agreement or the limited liability company agreement of the general partner, as such agreements may be amended from time to time.

As discussed in more detail in "Partnership Management," "Corporate Governance" and "ACG Committee" within Item 10, the ACG Committee is comprised of three directors: Rex C. Ross, Charles M. Rampacek and E. William Barnett. During the year ended December 31, 2008, the ACG Committee reviewed and approved the: (a) Second Amended and Restated Limited Liability Company Agreement of Mont Belvieu Caverns; and (b) the Texas Offshore Port System joint venture transaction.

Our management authorization policy currently requires board approval for the following types of transactions to the extent such transactions have a value in excess of $100.0 million thus triggering ACG Committee review under our ACG Committee Charter if such transaction is also a related party transaction:

- asset purchase or sale transactions;
- capital expenditures; and
- purchase orders and operating and administrative expenses not governed by the ASA.

The ASA governs numerous day-to-day transactions between us and our subsidiaries, our general partner and EPCO and its affiliates, including the provision by EPCO of administrative and other services to us and our subsidiaries and our reimbursement of costs, without markup or discount, for those services. The ACG Committee reviewed and recommended the ASA, and the Board approved it upon receiving such recommendation.

Related party transactions that do not occur under the ASA and that are not reviewed by the ACG Committee, as described above, are subject to the management authorization policy. This policy, which applies to related party transactions as well as transactions with unrelated parties, specifies thresholds for our general partner's officers and chairman of the Board to authorize various categories of transactions, including purchases and sales of assets, expenditures, commercial and financial transactions and legal agreements.

Partnership Agreement Standards for ACG Committee Review

Under our partnership agreement, whenever a potential conflict of interest exists or arises between our general partner or any of its affiliates and us, any of our subsidiaries or any partner any resolution or course of action by our general partner or its affiliates in respect to such conflict of interest is permitted and deemed approved by all of our partners, and will not constitute a breach of our partnership agreement or any agreement contemplated by such agreement, or of any duty stated or implied by law or equity, if the resolution or course of action is or, by operation of the partnership agreement is deemed to be, fair and reasonable to us; provided that, any conflict of interest and any resolution of such conflict of interest will be conclusively deemed fair and reasonable to us if such conflict of interest or resolution is (i) approved by a majority of the members of our ACG Committee ("Special Approval"), or (ii) on terms objectively demonstrable to be no less favorable to us than those generally being provided to or available from unrelated third parties.

The ACG Committee (in connection with Special Approval) is authorized in connection with its resolution of any conflict of interest to consider:

- the relative interests of any party to such conflict, agreement, transaction or situation and the benefits and burdens relating to such interest;
- the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to us);
- any customary or accepted industry practices and any customary or historical dealings with a particular person;
- any applicable generally accepted accounting or engineering practices or principles;
- the relative cost of capital of the parties and the consequent rates of return to the equity holders of the parties; and
- such additional factors as the committee determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances.

The review and approval process of the ACG Committee, including factual matters that may be considered in determining whether a transaction is fair and reasonable, is generally governed by Section 7.9 of our partnership agreement. As discussed above, the ACG Committee's Special Approval is conclusively deemed fair and reasonable to us under the partnership agreement.

The review and work performed by the ACG Committee with respect to a transaction varies depending upon the nature of the transaction and the scope of the ACG Committee's charge. Examples of functions the ACG Committee may, as it deems appropriate, perform in the course of reviewing a transaction include (but are not limited to):

- assessing the business rationale for the transaction;
- reviewing the terms and conditions of the proposed transaction, including consideration and financing requirements, if any;
- assessing the effect of the transaction on our earnings and distributable cash flow per unit, and on our results of operations, financial condition, properties or prospects;
- conducting due diligence, including by interviews and discussions with management and other representatives and by reviewing transaction materials and findings of management and other representatives;
- considering the relative advantages and disadvantages of the transactions to the parties;
- engaging third party financial advisors to provide financial advice and assistance, including by providing fairness opinions if requested;
- engaging legal advisors; and
- evaluating and negotiating the transaction and recommending for approval or approving the transaction, as the case may be.

Nothing contained in the partnership agreement requires the ACG Committee to consider the interests of any person other than the partnership. In the absence of bad faith by the ACG Committee or our general partner, the resolution, action or terms so made, taken or provided (including granting Special Approval) by the ACG Committee or our general partner with respect to such matter are conclusive and binding on all persons (including all of our partners) and do not constitute a breach of the partnership agreement, or any other agreement contemplated thereby, or a breach of any standard of care or duty imposed in the partnership agreement or under the Delaware Revised Uniform Limited Partnership Act or any other law, rule or regulation. The partnership agreement provides that it is presumed that the resolution, action or terms made, taken or provided by the ACG Committee or our general partner were not made, taken or provided in bad faith, and in any proceeding brought by any limited partner or by or on behalf of such limited partner or any other limited partner or us challenging such resolution, action or terms, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Director Independence

Messrs. Barnett, Ross and Rampacek have been determined to be independent under the applicable NYSE listing standards and are independent under the rules of the SEC applicable to audit committees. For a discussion of independence standards applicable to the Board and factors considered by the Board in making its independence determinations, please refer to "Corporate Governance" and "ACG Committee" under Item 10 of this annual report.

Item 14. ***Principal Accountant Fees and Services.***

We have engaged Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates (collectively, "Deloitte & Touche") as our independent registered public accounting firm and principal accountants. The following table summarizes fees we paid Deloitte & Touche for independent auditing, tax and related services for each of the last two fiscal years (dollars in thousands):

	For Year Ended December 31,	
	2008	**2007**
Audit Fees (1)	$ 4,387	$ 4,772
Audit-Related Fees (2)	--	79
Tax Fees (3)	569	341
All Other Fees (4)	--	--

(1) Audit fees represent amounts billed for each of the years presented for professional services rendered in connection with (i) the audit of our annual financial statements and internal controls over financial reporting, (ii) the review of our quarterly financial statements or (iii) those services normally provided in connection with statutory and regulatory filings or engagements including comfort letters, consents and other services related to SEC matters. This information is presented as of the latest practicable date for this annual report.

(2) Audit-related fees represent amounts we were billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews. This category primarily includes services relating to internal control assessments and accounting-related consulting.

(3) Tax fees represent amounts we were billed in each of the years presented for professional services rendered in connection with tax compliance, tax advice and tax planning. This category primarily includes services relating to the preparation of unitholder annual K-1 statements and partnership tax planning. In 2008, PricewaterhouseCoopers International Limited was engaged to perform the majority of tax related services.

(4) All other fees represent amounts we were billed in each of the years presented for services not classifiable under the other categories listed in the table above. No such services were rendered by Deloitte & Touche during the last two years.

The ACG Committee of our general partner has approved the use of Deloitte & Touche as our independent principal accountant. In connection with its oversight responsibilities, the ACG Committee has adopted a pre-approval policy regarding any services proposed to be performed by Deloitte & Touche. The pre-approval policy includes four primary service categories: Audit, Audit-related, Tax and Other.

In general, as services are required, management and Deloitte & Touche submit a detailed proposal to the ACG Committee discussing the reasons for the request, the scope of work to be performed, and an estimate of the fee to be charged by Deloitte & Touche for such work. The ACG Committee discusses the request with management and Deloitte & Touche, and if the work is deemed necessary and appropriate for Deloitte & Touche to perform, approves the request subject to the fee amount presented (the initial "pre-approved" fee amount). As part of these discussions, the ACG Committee must determine whether or not the proposed services are permitted under the rules and regulations concerning auditor independence under the Sarbanes-Oxley Act of 2002 as well as rules of the American Institute of Certified Public Accountants. If at a later date, it appears that the initial pre-approved fee amount may be insufficient to complete the work, then management and Deloitte & Touche must present a request to the ACG Committee to increase the approved amount and the reasons for the increase.

Under the pre-approval policy, management cannot act upon its own to authorize an expenditure for services outside of the pre-approved amounts. On a quarterly basis, the ACG Committee is provided a schedule showing Deloitte & Touche's pre-approved amounts compared to actual fees billed for each of the primary service categories. The ACG Committee's pre-approval process helps to ensure the independence of our principal accountant from management.

In order for Deloitte & Touche to maintain its independence, we are prohibited from using them to perform general bookkeeping, management or human resource functions, and any other service not permitted by the Public Company Accounting Oversight Board. The ACG Committee's pre-approval policy also precludes Deloitte & Touche from performing any of these services for us.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules*.**

(a) The following documents are filed as a part of this Report:

(1) Financial Statements: See Index to Consolidated Financial Statements on page F-1 of this Report for financial statements filed as part of this Report.

(2) Financial Statement Schedules: All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(3) Exhibits. The agreements included as exhibits are included only to provide information to investors regarding their terms. The agreements listed below may contain representations, warranties and other provisions that were made, among other things, to provide the parties thereto with specified rights and obligations and to allocate risk among them, and such agreements should not be relied upon as constituting or providing any factual disclosures about us, any other persons, any state of affairs or other matters.

Exhibit Number	Exhibit*
2.1	Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed December 15, 2003).
2.2	Amendment No. 1 to Merger Agreement, dated as of August 31, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2004).
2.3	Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.2 to Form 8-K filed December 15, 2003).
2.4	Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.1 to the Form 8-K filed April 21, 2004).
2.5	Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (incorporated by reference to Exhibit 2.4 to Form 8-K filed December 15, 2003).
3.1	Certificate of Limited Partnership of Enterprise Products Partners L.P. (incorporated by reference to Exhibit 3.6 to Form 10-Q filed November 9, 2007).
3.2	Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 8, 2005 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 10, 2005).
3.3	First Amendment to the Fifth Amended and Restated Partnership Agreement of Enterprise Products Partners L.P. dated as of December 27, 2007 (incorporated by reference to Exhibit 3.1 to Form 8-K/A filed January 3, 2008).
3.4	Second Amendment to the Fifth Amended and Restated Partnership Agreement of Enterprise Products Partners L.P. dated as of April 14, 2008 (incorporated by reference to Exhibit 10.1 to Form 8-K filed April 16, 2008).
3.5	Third Amendment to the Fifth Amended and Restated Partnership Agreement of Enterprise

	Products Partners L.P. dated as of November 6, 2008 (incorporated by reference to Exhibit 3.5 to Form 10-Q filed on November 10, 2008).
3.6	Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated as of November 7, 2007 (incorporated by reference to Exhibit 3.2 to Form 10-Q filed November 9, 2007).
3.7	First Amendment to Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated as of November 6, 2008 (incorporated by reference to Exhibit 3.7 to Form 10-Q filed on November 10, 2008).
3.8	Limited Liability Company Agreement of Enterprise Products Operating LLC dated as of June 30, 2007 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed on August 8, 2007).
3.9	Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.10	Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.11	Certificate of Limited Partnership of Duncan Energy Partners L.P. (incorporated by reference to Exhibit 3.1 to Duncan Energy Partners L.P.'s Form S-1 Registration Statement, Reg. No. 333-138371, filed November 2, 2006).
3.12	Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P., dated February 5, 2007 (incorporated by reference to Exhibit 3.1 to Duncan Energy Partners L.P.'s Form 8-K filed February 5, 2007).
3.13	First Amendment to Amended and Restated Partnership Agreement of Duncan Energy Partners L.P. dated as of December 27, 2007 (incorporated by reference to Exhibit 3.1 to Duncan Energy Partners L.P.'s Form 8-K/A filed on January 3, 2008).
4.1	Form of Common Unit certificate (incorporated by reference to Exhibit 4.1 to Registration Statement on Form S-1/A; File No. 333-52537, filed July 21, 1998).
4.2	Indenture dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000).
4.3	First Supplemental Indenture dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.4	Second Supplemental Indenture dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed March 31, 2003).
4.5	Third Supplemental Indenture dated as of June 30, 2007, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and U.S. Bank National Association, as successor Trustee (incorporated by reference to Exhibit 4.55 to Form 10-Q filed on August 8, 2007).
4.6	Amended and Restated Revolving Credit Agreement dated as of November 19, 2007 among Enterprise Products Operating LLC, the financial institutions party thereto as lenders, Wachovia Bank, National Association, as Administrative Agent, Issuing Bank and Swingline Lender, Citibank, N.A. and JPMorgan Chase Bank, as Co-Syndication Agents, and SunTrust Bank, Mizuho Corporate Bank, Ltd. and The Bank of Nova Scotia, as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to Form 8-K filed on November 20, 2007).
4.7	Amended and Restated Guaranty Agreement dated as of November 19, 2007 executed by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent (incorporated by reference to Exhibit 10.2 to Form 8-K filed on November 20, 2007).
4.8	Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed on October 6, 2004).
4.9	First Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating

	L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed on October 6, 2004).
4.10	Second Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on October 6, 2004).
4.11	Third Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed on October 6, 2004).
4.12	Fourth Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Form 8-K filed on October 6, 2004).
4.13	Fifth Supplemental Indenture dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed on March 3, 2005).
4.14	Sixth Supplemental Indenture dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on March 3, 2005).
4.15	Seventh Supplemental Indenture dated as of June 1, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.46 to Form 10-Q filed November 4, 2005).
4.16	Eighth Supplemental Indenture dated as of July 18, 2006 to Indenture dated October 4, 2004 among Enterprise Products Operating L.P., as issuer, Enterprise Products Partners L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.17	Ninth Supplemental Indenture, dated as of May 24, 2007, by and among Enterprise Products Operating L.P., as issuer, Enterprise Products Partners L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed by Enterprise Products Partners L.P. on May 24, 2007).
4.18	Tenth Supplemental Indenture, dated as of June 30, 2007, by and among Enterprise Products Operating LLC, as issuer, Enterprise Products Partners L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.54 to Form 10-Q filed August 8, 2007).
4.19	Eleventh Supplemental Indenture, dated as of September 4, 2007, by and among Enterprise Products Operating LLC, as issuer, Enterprise Products Partners L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on September 5, 2007).
4.20	Twelfth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008).
4.21	Thirteenth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).
4.22	Fourteenth Supplemental Indenture, dated as of December 8, 2008, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed December 8, 2008).
4.23	Global Note representing $350.0 million principal amount of 6.375% Series B Senior Notes due

2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).

4.24 Global Note representing $500.0 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 10-K filed March 31, 2003).

4.25 Global Notes representing $450.0 million principal amount of 7.50% Senior Notes due 2011 (incorporated by reference to Exhibit 4.1 to Form 8-K filed January 25, 2001).

4.26 Global Note representing $500.0 million principal amount of 4.00% Series B Senior Notes due 2007 with attached Guarantee (incorporated by reference to Exhibit 4.14 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).

4.27 Global Note representing $500.0 million principal amount of 5.60% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.17 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).

4.28 Global Note representing $150.0 million principal amount of 5.60% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.18 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).

4.29 Global Note representing $350.0 million principal amount of 6.65% Series B Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).

4.30 Global Note representing $500.0 million principal amount of 4.625% Series B Senior Notes due 2009 with attached Guarantee (incorporated by reference to Exhibit 4.27 to Form 10-K for the year ended December 31, 2004 filed on March 15, 2005).

4.31 Global Note representing $250.0 million principal amount of 5.00% Series B Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.31 to Form 10-Q filed on November 4, 2005).

4.32 Global Note representing $250.0 million principal amount of 5.75% Series B Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed on November 4, 2005).

4.33 Global Note representing $500.0 million principal amount of 4.95% Senior Notes due 2010 with attached Guarantee (incorporated by reference to Exhibit 4.47 to Form 10-Q filed November 4, 2005).

4.34 Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed July 19, 2006).

4.35 Global Note representing $800.0 million principal amount of 6.30% Senior Notes due 2017 with attached Guarantee (incorporated by reference to Exhibit 4.38 to Form 10-Q filed November 9, 2007).

4.36 Form of Global Note representing $400.0 million principal amount of 5.65% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008).

4.37 Form of Global Note representing $700.0 million principal amount of 6.50% Senior Notes due 2019 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).

4.38 Form of Global Note representing $500.0 million principal amount of 9.75% Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed December 8, 2008).

4.39 Amended and Restated Credit Agreement dated as of June 29, 2005, among Cameron Highway Oil Pipeline Company, the Lenders party thereto, and SunTrust Bank, as Administrative Agent and Collateral Agent (incorporated by reference to Exhibit 4.1 to Form 8-K filed on July 1, 2005).

4.40 Replacement Capital Covenant, dated May 24, 2007, executed by Enterprise Products Operating L.P. and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed by Enterprise Products Partners L.P. on May 24, 2007).

4.41 First Amendment to Replacement Capital Covenant dated August 25, 2006, executed by Enterprise Products Operating L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.2 to Form 8-K filed August 25, 2006).

4.42 Purchase Agreement, dated as of July 12, 2006 between Cerrito Gathering Company, Ltd., Cerrito

Gas Marketing, Ltd., Encinal Gathering, Ltd., as Sellers, Lewis Energy Group, L.P. as Guarantor, and Enterprise Products Partners L.P., as buyer (incorporated by reference to Exhibit 4.6 to Form 10-Q filed August 8, 2006).

10.1	Transportation Contract between Enterprise Products Operating L.P. and Enterprise Transportation Company dated June 1, 1998 (incorporated by reference to Exhibit 10.3 to Registration Statement Form S-1/A filed July 8, 1998).
10.2***	Enterprise Products 1998 Long-Term Incentive Plan, amended and restated as of November 9 2007 (incorporated by reference to Exhibit 10.1 to Form 10-Q filed on November 9, 2007).
10.3***	Form of Option Grant Award under Enterprise Products 1998 Long-Term Incentive Plan for awards issued after May 7, 2008 (incorporated by reference to Exhibit 10.4 to Form 10-Q filed on May 12, 2008).
10.4	Amendment to Form of Option Grant Award under Enterprise Products 1998 Long-Term Incentive Plan for awards issued after April 10, 2007 but before May 7, 2008 (incorporated by reference to Exhibit 10.5 to Form 10-Q filed on May 12, 2008).
10.5***	Form of Restricted Unit Grant under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 10-Q filed on November 9, 2007).
10.6***	EPE Unit L.P. Agreement of Limited Partnership (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Enterprise GP Holdings L.P., Commission file no. 1-32610, on September 1, 2005).
10.7***	First Amendment to EPE Unit L.P. Agreement of Limited Partnership dated August 7, 2007 (incorporated by reference to Exhibit 10.3 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007).
10.8***	Second Amendment to EPE Unit L.P. Agreement of Limited Partnership dated July 1, 2008 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Enterprise GP Holdings L.P. on July 7, 2008).
10.9***	EPE Unit II, L.P. Agreement of Limited Partnership (incorporated by reference to Exhibit 10.13 to Form 10-K filed on February 28, 2007).
10.10***	First Amendment to EPE Unit II, L.P. Agreement of limited partnership dated August 7, 2007 (incorporated by reference to Exhibit 10.4 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007).
10.11***	Second Amendment to EPE Unit II, L.P. Agreement of limited partnership dated July 1, 2008 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Enterprise GP Holdings L.P. on July 7, 2008).
10.12***	EPE Unit III, L.P. Agreement of Limited Partnership dated May 7, 2007 (incorporated by reference to Exhibit 10.6 to the Current Report on Form 8-K filed by Enterprise GP Holdings L.P. on May 10, 2007).
10.13***	First Amendment to EPE Unit III, L.P. Agreement of limited partnership dated August 7, 2007 (incorporated by reference to Exhibit 10.5 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007).
10.14***	Second Amendment to Agreement of Limited Partnership of EPE Unit III, L.P. dated July 1, 2008 (incorporated by reference to Exhibit 10.3 to the Current Report Form 8-K filed by Enterprise GP Holdings L.P. on July 7, 2008).
10.15	Enterprise Unit L.P. Agreement of Limited Partnership dated February 20, 2008 (incorporated by reference to Exhibit 10.1 to the Form 8-K filed on February 26, 2008).
10.16	EPCO Unit L.P. Agreement of Limited Partnership dated November 13, 2008 (incorporated by reference to Exhibit 10.5 to the Form 8-K filed on November 18, 2008).
10.17***	Enterprise Products Company 2005 EPE Long-Term Incentive Plan (amended and restated) (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Enterprise GP Holdings L.P. on May 8, 2006).
10.18***	Form of Restricted Unit Grant under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.29 to Amendment No. 3 to Form S-1 Registration Statement (Reg. No. 333-124320) filed by Enterprise GP Holdings L.P. on August 11, 2005).
10.19***	Form of Phantom Unit Grant under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.30 to Amendment No. 3 to Form S-1 Registration Statement (Reg. No. 333-124320) filed by Enterprise GP Holdings L.P. on August

11, 2005).

10.20*** Form of Unit Appreciation Right Grant (Enterprise Products GP, LLC Directors) based upon the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8-K filed by Enterprise GP Holdings on May 8, 2006).

10.21*** Amended and Restated Enterprise Products 2008 Long-Term Incentive Plan (incorporated by reference to Exhibit 4.1 to the Registration Statement on Form S-8 filed on May 6, 2008).

10.22*** Form of Restricted Unit Grant under the Amended and Restated Enterprise Products 2008 Long-Term Incentive Plan (incorporated by reference to Exhibit 4.2 to the Registration Statement on Form S-8 filed on May 6, 2008).

10.23*** Form of Option Grant under the Amended and Restated Enterprise Products 2008 Long-Term Incentive Plan (incorporated by reference to Exhibit 4.3 to the Registration Statement on Form S-8 filed on May 6, 2008).

10.24 Fifth Amended and Restated Administrative Services Agreement by and among EPCO, Inc., Enterprise GP Holdings L.P., EPE Holdings, LLC, Enterprise Products Partners L.P., Enterprise Products Operating LLC, Enterprise Products GP, LLC, Enterprise Products OLPGP, Inc., DEP Holdings, LLC, Duncan Energy Partners L.P., DEP Operating Partnership L.P., TEPPCO Partners, L.P., Texas Eastern Products Pipeline Company, LLC, TE Products Pipeline Company, LLC, TEPPCO Midstream Companies, LLC, TCTM, L.P. and TEPPCO GP, Inc. dated effective as of January 30, 2009 (incorporated by reference to Exhibit 10.1 to Form 8-K filed February 5, 2009).

10.25 Omnibus Agreement, dated as of February 5, 2007 by and among Enterprise Products Operating L.P., DEP Holdings, LLC, Duncan Energy Partners L.P., DEP OLPGP, LLC, DEP Operating Partnership, L.P., Enterprise Lou-Tex Propylene Pipeline L.P., Sabine Propylene Pipeline L.P., Acadian Gas, LLC, Mont Belvieu Caverns, LLC, South Texas NGL Pipelines, LLC (incorporated by reference to Exhibit 10.19 to Form 8-K filed February 5, 2007 by Duncan Energy Partners).

10.26 Contribution, Conveyance and Assumption Agreement dated as of February 5, 2007, by and among Enterprise Products Operating L.P., DEP Holdings, LLC, Duncan Energy Partners L.P., DEP OLPGP, LLC and DEP Operating Partnership, L.P. (incorporated by reference to Exhibit 10.1 to Form 8-K filed February 5, 2007 by Duncan Energy Partners).

10.27 Agreement and Release, dated May 31, 2007, between EPCO, Inc. and Robert G. Phillips (incorporated by reference to Exhibit 10.3 to Form 10-Q filed on August 8, 2007).

10.28 Revolving Credit Agreement, dated as of January 5, 2007, among Duncan Energy Partners L.P., as borrower, Wachovia Bank, National Association, as Administrative Agent, The Bank of Nova Scotia and Citibank, N.A., as Co-Syndication Agents, JPMorgan Chase Bank, N.A. and Mizuho Corporate Bank, Ltd., as Co-Documentation Agents, and Wachovia Capital Markets, LLC, The Bank of Nova Scotia and Citigroup Global Markets Inc., as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 10.20 to Amendment No. 2 to Duncan Energy Partners L.P.'s Form S-1 Registration Statement (Reg. No. 333-138371) filed January 12, 2007).

10.29 First Amendment to Revolving Credit Agreement, dated as of June 30, 2007, among Duncan Energy Partners L.P., as borrower, Wachovia Bank, National Association, as Administrative Agent, The Bank of Nova Scotia and Citibank, N.A., as Co-Syndication Agents, JPMorgan Chase Bank, N.A. and Mizuho Corporate Bank, Ltd., as Co-Documentation Agents, and Wachovia Capital Markets, LLC, The Bank of Nova Scotia and Citigroup Global Markets Inc., as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 4.2 to Form 10-Q filed August 8, 2007 by Duncan Energy Partners).

10.30 Term Loan Credit Agreement dated as of November 12, 2008 among Enterprise Products Operating LLC, the financial institutions party thereto as lenders, Mizuho Corporate Bank, Ltd., as administrative agent, a lender and as sole lead arranger (incorporated by reference to Exhibit 10.1 to Form 8-K on November 18, 2008).

10.31 Guaranty Agreement dated as of November 12, 2008 executed by Enterprise Products Partners L.P. in favor of Mizuho Corporate Bank, Ltd., as administrative agent (incorporated by reference to Exhibit 10.2 to Form 8-K on November 18, 2008).

10.32 364-Day Revolving Credit Agreement dated as of November 17, 2008 among Enterprise Products Operating LLC, the financial institutions party thereto as lenders, The Royal Bank of Scotland plc, as administrative agent, and Barclays Bank plc, The Bank of Nova Scotia, DnB NOR Bank ASA and Wachovia Bank, National Association, as co-arrangers (incorporated by reference to

	Exhibit 10.3 to Form 8-K on November 18, 2008).
10.33	Guaranty Agreement dated as of November 17, 2008 executed by Enterprise Products Partners L.P. in favor of The Royal Bank of Scotland plc, as administrative agent (incorporated by reference to Exhibit 10.4 to Form 8-K on November 18, 2008).
10.34*	Second Amended and Restated Limited Liability Company Agreement of Mont Belvieu Caverns, LLC, dated November 6, 2008 (incorporated by reference to Exhibit 10.4 to Form 10-Q filed by Duncan Energy Partners L.P. on November 10, 2008).
12.1#	Computation of ratio of earnings to fixed charges for each of the five years ended December 31, 2008, 2007, 2006, 2005 and 2004.
21.1#	List of subsidiaries as of February 2, 2009.
23.1#	Consent of Deloitte & Touche LLP.
31.1#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the December 31, 2008 annual report on Form 10-K.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P. for the December 31, 2008 annual report on Form 10-K.
32.1#	Section 1350 certification of Michael A. Creel for the December 31, 2008 annual report on Form 10-K.
32.2#	Section 1350 certification of W. Randall Fowler for the December 31, 2008 annual report on Form 10-K.

* With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file number for Enterprise Products Partners L.P., Duncan Energy Partners L.P. and Enterprise GP Holdings L.P. are 1-14323, 1-33266 and 1-32610, respectively.

*** Identifies management contract and compensatory plan arrangements.

\# Filed with this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on March 2, 2009.

ENTERPRISE PRODUCTS PARTNERS L.P.
(A Delaware Limited Partnership)

By: Enterprise Products GP, LLC, as General Partner

By: /s/ Michael J. Knesek
Name: Michael J. Knesek
Title: Senior Vice President, Controller
and Principal Accounting Officer
of the General Partner

Pursuant to the requirements of the Securities Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated below on March 2, 2009.

Signature	Title (Position with Enterprise Products GP, LLC)
/s/ Dan L. Duncan Dan L. Duncan	Director and Chairman
/s/ Michael A. Creel Michael A. Creel	Director, President and Chief Executive Officer
/s/ W. Randall Fowler W. Randall Fowler	Director, Executive Vice President and Chief Financial Officer
/s/ Richard H. Bachmann Richard H. Bachmann	Director, Executive Vice President, Chief Legal Officer and Secretary
/s/ A. J. Teague A. J. Teague	Director, Executive Vice President and Chief Commercial Officer
/s/ Dr. Ralph S. Cunningham Dr. Ralph S. Cunningham	Director
/s/ E. William Barnett E. William Barnett	Director
/s/ Rex C. Ross Rex C. Ross	Director
/s/ Charles M. Rampacek Charles M. Rampacek	Director
/s/ Michael J. Knesek Michael J. Knesek	Senior Vice President, Controller and Principal Accounting Officer

Financial Statements and Supplementary Data.

ENTERPRISE PRODUCTS PARTNERS L.P.
INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products GP, LLC and
Unitholders of Enterprise Products Partners L.P.
Houston, Texas

We have audited the accompanying consolidated balance sheets of Enterprise Products Partners L.P. and subsidiaries (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of operations, comprehensive income, cash flows, and partners' equity for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Enterprise Products Partners L.P. and subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 2, 2009 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 2, 2009

ENTERPRISE PRODUCTS PARTNERS L.P.
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	December 31,	
ASSETS	**2008**	**2007**
Current assets:		
Cash and cash equivalents	$ 35,373	$ 39,722
Restricted cash	203,789	53,144
Accounts and notes receivable – trade, net of allowance for doubtful accounts of $15,123 at December 31, 2008 and $21,659 at December 31, 2007	1,185,515	1,930,762
Accounts receivable – related parties	61,629	79,782
Inventories	362,815	354,282
Derivative assets	202,826	1,649
Prepaid and other current assets	111,773	78,544
Total current assets	2,163,720	2,537,885
Property, plant and equipment, net	13,154,774	11,587,264
Investments in and advances to unconsolidated affiliates	949,526	858,339
Intangible assets, net of accumulated amortization of $429,872 at December 31, 2008 and $341,494 at December 31, 2007	855,416	917,000
Goodwill	706,884	591,652
Deferred tax asset	355	3,522
Other assets, including restricted cash of $17,871 at December 31, 2007	126,860	112,345
Total assets	$ 17,957,535	$ 16,608,007
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable – trade	$ 300,532	$ 324,999
Accounts payable – related parties	39,558	24,432
Accrued product payables	1,142,370	2,227,489
Accrued expenses	48,772	47,756
Accrued interest	151,873	130,971
Derivative liabilities	287,161	41,811
Other current liabilities	252,883	247,225
Total current liabilities	2,223,149	3,044,683
Long-term debt: (see Note 14)		
Senior debt obligations – principal	7,813,346	5,646,500
Junior subordinated notes – principal	1,232,700	1,250,000
Other	62,364	9,645
Total long-term debt	9,108,410	6,906,145
Deferred tax liabilities	66,062	21,364
Other long-term liabilities	81,277	73,748
Minority interest	393,649	430,418
Commitments and contingencies		
Partners' equity: (see Note 15)		
Limited Partners:		
Common units (439,354,731 units outstanding at December 31, 2008 and 433,608,763 units outstanding at December 31, 2007)	6,036,887	5,976,947
Restricted common units (2,080,600 units outstanding at December 31, 2008 and 1,688,540 units outstanding at December 31, 2007)	26,219	15,948
General partner	123,599	122,297
Accumulated other comprehensive income (loss)	(101,717)	16,457
Total partners' equity	6,084,988	6,131,649
Total liabilities and partners' equity	$ 17,957,535	$ 16,608,007

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED OPERATIONS
(Dollars in thousands, except per unit amounts)

	For Year Ended December 31,		
	2008	2007	2006
Revenues:			
Third parties	$ 20,769,206	$ 16,297,409	$ 13,587,739
Related parties	1,136,450	652,716	403,230
Total revenues (see Note 16)	21,905,656	16,950,125	13,990,969
Costs and expenses:			
Operating costs and expenses:			
Third parties	19,814,572	15,646,587	12,745,948
Related parties	646,392	362,464	343,143
Total operating costs and expenses	20,460,964	16,009,051	13,089,091
General and administrative costs:			
Third parties	31,543	31,177	22,126
Related parties	59,007	56,518	41,265
Total general and administrative costs	90,550	87,695	63,391
Total costs and expenses	20,551,514	16,096,746	13,152,482
Equity in earnings of unconsolidated affiliates	59,104	29,658	21,565
Operating income	1,413,246	883,037	860,052
Other income (expense):			
Interest expense	(400,686)	(311,764)	(238,023)
Interest income	5,523	8,601	7,589
Other, net	3,715	(300)	467
Total other expense, net	(391,448)	(303,463)	(229,967)
Income before provision for income taxes, minority interest and the cumulative effect of change in accounting principle	1,021,798	579,574	630,085
Provision for income taxes	(26,401)	(15,257)	(21,323)
Income before minority interest and the cumulative effect of change in accounting principle	995,397	564,317	608,762
Minority interest	(41,376)	(30,643)	(9,079)
Income before the cumulative effect of change in accounting principle	954,021	533,674	599,683
Cumulative effect of change in accounting principle (see Note 8)	--	--	1,472
Net income	$ 954,021	$ 533,674	$ 601,155
Net income allocation: (see Note 15)			
Net income available to limited partners	$ 811,547	$ 417,728	$ 504,156
Net income available to general partner	$ 142,474	$ 115,946	$ 96,999
Earnings per unit: (see Note 19)			
Basic and diluted income per unit before change in accounting principle	$ 1.85	$ 0.96	$ 1.22
Basic and diluted income per unit	$ 1.85	$ 0.96	$ 1.22

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME
(Dollars in thousands)

	For Year Ended December 31,		
	2008	**2007**	**2006**
Net income	$ 954,021	$ 533,674	$ 601,155
Other comprehensive income (loss):			
Cash flow hedges:			
Commodity financial instrument gains (losses) during period	(150,865)	(25,860)	8,942
Reclassification adjustment for (gains) losses included in net income related to commodity financial instruments	58,407	7,863	(12,564)
Interest rate financial instrument gains (losses) during period	(28,761)	14,725	11,196
Reclassification adjustment for gains included in net income related to interest rate financial instruments	(2,401)	(5,779)	(4,234)
Foreign currency hedge gains	9,286	1,308	--
Total cash flow hedges	(114,334)	(7,743)	3,340
Foreign currency translation adjustment	(2,501)	2,007	(807)
Change in funded status of pension and postretirement plans, net of tax	(1,339)	(52)	--
Total other comprehensive income (loss)	(118,174)	(5,788)	2,533
Comprehensive income	$ 835,847	$ 527,886	$ 603,688

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in thousands)

	For Year Ended December 31,		
	2008	**2007**	**2006**
Operating activities:			
Net income	$ 954,021	$ 533,674	$ 601,155
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion in operating costs and expenses	555,370	513,840	440,256
Depreciation and amortization in general and administrative costs	10,659	10,258	7,186
Amortization in interest expense	(3,858)	(336)	766
Equity in earnings of unconsolidated affiliates	(59,104)	(29,658)	(21,565)
Distributions received from unconsolidated affiliates	98,553	73,593	43,032
Provision for impairment of long-lived asset	--	--	88
Cumulative effect of change in accounting principle	--	--	(1,472)
Operating lease expense paid by EPCO, Inc.	2,038	2,105	2,109
Minority interest	41,376	30,643	9,079
Loss (gain) from asset sales and related transactions	(3,746)	5,391	(3,359)
Loss (gain) on early extinguishment of debt	(7,093)	250	--
Deferred income tax expense	6,199	8,306	14,427
Changes in fair market value of financial instruments	198	981	(51)
Effect of pension settlement recognition	(114)	588	--
Net effect of changes in operating accounts (see Note 22)	(357,430)	441,306	83,418
Net cash flows provided by operating activities	1,237,069	1,590,941	1,175,069
Investing activities:			
Capital expenditures	(1,979,459)	(2,185,800)	(1,341,070)
Contributions in aid of construction costs	25,783	57,547	60,492
Proceeds from asset sales and related transactions	15,999	12,027	3,927
Increase in restricted cash	(132,775)	(47,347)	(8,715)
Cash used for business combinations (see Note 12)	(202,160)	(35,793)	(276,500)
Acquisition of intangible assets	(5,126)	(11,232)	--
Investments in unconsolidated affiliates	(129,816)	(332,909)	(138,266)
Advances from (to) unconsolidated affiliates	(4,315)	(10,100)	10,844
Cash used in investing activities	(2,411,869)	(2,553,607)	(1,689,288)
Financing activities:			
Borrowings under debt agreements	8,683,450	6,024,518	3,378,285
Repayments of debt	(6,528,126)	(4,458,141)	(2,907,000)
Debt issuance costs	(17,584)	(16,511)	(8,955)
Distributions paid to partners	(1,037,373)	(957,705)	(843,292)
Distributions paid to minority interests	(55,851)	(32,326)	(8,831)
Proceeds from initial public offering of Duncan Energy Partners in minority interests (see Notes 2 and 17)	--	290,466	--
Other contributions from minority interests	28	12,506	27,578
Net proceeds from issuance of common units	142,777	69,221	857,187
Repurchase of restricted option awards	--	(1,568)	--
Acquisition of treasury units	(1,911)	--	--
Monetization of interest rate hedging financial instruments (see Note 7)	(14,444)	48,895	--
Cash provided by financing activities	1,170,966	979,355	494,972
Effect of exchange rate changes on cash	(515)	414	(232)
Net change in cash and cash equivalents	(3,834)	16,689	(19,247)
Cash and cash equivalents, January 1	39,722	22,619	42,098
Cash and cash equivalents, December 31	$ 35,373	$ 39,722	$ 22,619

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED PARTNERS' EQUITY
(See Note 15 for Unit History, Detail of Changes in Limited Partners' Equity and Accumulated Other Comprehensive Income (Loss))
(Dollars in thousands)

	Limited Partners	General Partner	Deferred Compensation	Accumulated Other Comprehensive Income (Loss)	Total
Balance, December 31, 2005	$ 5,561,338	$ 113,496	$ (14,597)	$ 19,072	$ 5,679,309
Net income	504,156	96,999	--	--	601,155
Operating leases paid by EPCO, Inc.	2,067	42	--	--	2,109
Cash distributions to partners	(739,632)	(101,805)	--	--	(841,437)
Unit option reimbursements to EPCO, Inc.	(1,818)	(41)	--	--	(1,859)
Net proceeds from issuance of common units	830,825	16,943	--	--	847,768
Common units issued to Lewis in connection with Encinal acquisition	181,112	3,705	--	--	184,817
Proceeds from exercise of unit options	5,601	114	--	--	5,715
Change in accounting method for equity awards (see Note 8)	(15,815)	(307)	14,597	--	(1,525)
Amortization of equity awards	8,282	155	--	--	8,437
Change in funded status of pension and postretirement plans, net of tax	--	--	--	(464)	(464)
Foreign currency translation adjustment	--	--	--	(807)	(807)
Acquisition-related disbursement of cash	(6,199)	(126)	--	--	(6,325)
Cash flow hedges	--	--	--	3,340	3,340
Balance, December 31, 2006	6,329,917	129,175	--	21,141	6,480,233
Net income	417,728	115,946	--	--	533,674
Operating leases paid by EPCO, Inc.	2,063	42	--	--	2,105
Cash distributions to partners	(833,793)	(124,388)	--	--	(958,181)
Unit option reimbursements to EPCO, Inc.	(2,999)	(58)	--	--	(3,057)
Net proceeds from issuance of common units	60,445	1,232	--	--	61,677
Proceeds from exercise of unit options	7,549	154	--	--	7,703
Repurchase of restricted units and options	(1,568)	--	--	--	(1,568)
Amortization of equity awards	13,553	194	--	--	13,747
Change in funded status of pension and postretirement plans, net of tax	--	--	--	1,052	1,052
Foreign currency translation adjustment	--	--	--	2,007	2,007
Cash flow hedges	--	--	--	(7,743)	(7,743)
Balance, December 31, 2007	5,992,895	122,297	--	16,457	6,131,649
Net income	811,547	142,474	--	--	954,021
Operating leases paid by EPCO, Inc.	1,997	41	--	--	2,038
Cash distributions to partners	(892,693)	(144,130)	--	--	(1,036,823)
Unit option reimbursements to EPCO, Inc.	(550)	--	--	--	(550)
Non-cash distributions	(7,140)	(144)	--	--	(7,284)
Acquisition of treasury units	(1,873)	(38)	--	--	(1,911)
Net proceeds from issuance of common units	139,248	2,842	--	--	142,090
Proceeds from exercise of unit options	679	8	--	--	687
Amortization of equity awards	18,996	249	--	--	19,245
Change in funded status of pension and postretirement plans, net of tax	--	--	--	(1,339)	(1,339)
Foreign currency translation adjustment	--	--	--	(2,501)	(2,501)
Cash flow hedges	--	--	--	(114,334)	(114,334)
Balance, December 31, 2008	$ 6,063,106	$ 123,599	$ --	$ (101,717)	$ 6,084,988

See Notes to Consolidated Financial Statements.

Except per unit amounts, or as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.

Note 1. Partnership Organization

Enterprise Products Partners L.P. is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." Unless the context requires otherwise, references to "we," "us," "our" or "Enterprise Products Partners" are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries.

We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO, Inc. ("EPCO"). We conduct substantially all of our business through our wholly owned subsidiary, Enterprise Products Operating LLC ("EPO"), as successor in interest by merger to Enterprise Products Operating L.P. We are owned 98.0% by our limited partners and 2.0% by Enterprise Products GP, LLC (our general partner, referred to as "EPGP"). EPGP is owned 100.0% by Enterprise GP Holdings L.P. ("Enterprise GP Holdings"), a publicly traded affiliate, the units of which are listed on the NYSE under the ticker symbol "EPE." The general partner of Enterprise GP Holdings is EPE Holdings, LLC ("EPE Holdings"), a wholly owned subsidiary of Dan Duncan LLC, the membership interests of which are owned by Dan L. Duncan. We, EPGP, Enterprise GP Holdings, EPE Holdings and Dan Duncan LLC are affiliates and under common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO.

References to "TEPPCO" mean TEPPCO Partners, L.P., a publicly traded affiliate, the common units of which are listed on the NYSE under the ticker symbol "TPP." References to "TEPPCO GP" refer to Texas Eastern Products Pipeline Company, LLC, which is the general partner of TEPPCO and is wholly owned by Enterprise GP Holdings.

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries. References to "LE GP" mean LE GP, LLC, which is the general partner of Energy Transfer Equity. On May 7, 2007, Enterprise GP Holdings acquired non-controlling interests in both LE GP and Energy Transfer Equity. Enterprise GP Holdings accounts for its investments in LE GP and Energy Transfer Equity using the equity method of accounting.

References to "Employee Partnerships" mean EPE Unit L.P. ("EPE Unit I"), EPE Unit II, L.P. ("EPE Unit II"), EPE Unit III, L.P. ("EPE Unit III"), Enterprise Unit L.P. ("Enterprise Unit") and EPCO Unit L.P. ("EPCO Unit"), collectively, all of which are private company affiliates of EPCO.

On February 5, 2007, a consolidated subsidiary of ours, Duncan Energy Partners L.P. ("Duncan Energy Partners"), completed an initial public offering of its common units (see Note 17). Duncan Energy Partners owns equity interests in certain of our midstream energy businesses. References to "DEP GP" mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and is wholly owned by EPO.

On December 8, 2008, Duncan Energy Partners entered into a Purchase and Sale Agreement (the "DEP II Purchase Agreement") with EPO and Enterprise GTM Holdings L.P. ("Enterprise GTM," a wholly owned subsidiary of EPO). Pursuant to the DEP II Purchase Agreement, DEP Operating Partnership L.P. ("DEP OLP") acquired 100.0% of the membership interests in Enterprise III, LLC ("Enterprise III") from Enterprise GTM, thereby acquiring a 66.0% general partner interest in Enterprise GC, L.P. ("Enterprise GC"), a 51.0% general partner interest in Enterprise Intrastate L.P. ("Enterprise Intrastate") and a 51.0% membership interest in Enterprise Texas Pipeline LLC ("Enterprise Texas"). Collectively, we refer to Enterprise GC, Enterprise Intrastate and Enterprise Texas as the "DEP II Midstream Businesses." EPO was the sponsor of this second dropdown transaction. Enterprise GTM retained the remaining general partner and member interests in the DEP II Midstream Businesses (see Note 17).

For financial reporting purposes, we consolidate the financial statements of Duncan Energy Partners with those of our own and reflect its operations in our business segments. We control Duncan Energy Partners through our ownership of its general partner. Also, due to common control of the entities by Dan L. Duncan, the initial consolidated balance sheet of Duncan Energy Partners reflects our historical carrying basis in each of the subsidiaries contributed to Duncan Energy Partners. Public ownership of Duncan Energy Partners' net assets and earnings are presented as a component of minority interest in our consolidated financial statements. The borrowings of Duncan Energy Partners are presented as part of our consolidated debt; however, neither Enterprise Products Partners L.P. nor EPO have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

Note 2. Summary of Significant Accounting Policies

Allowance for Doubtful Accounts

Our allowance for doubtful accounts is determined based on specific identification and estimates of future uncollectible accounts. Our procedure for determining the allowance for doubtful accounts is based on (i) historical experience with customers, (ii) the perceived financial stability of customers based on our research and (iii) the levels of credit we grant to customers. In addition, we may increase the allowance account in response to the specific identification of customers involved in bankruptcy proceedings and similar financial difficulties. On a routine basis, we review estimates associated with the allowance for doubtful accounts to ensure that we have recorded sufficient reserves to cover potential losses. Our allowance also includes estimates for uncollectible natural gas imbalances based on specific identification of accounts.

The following table presents the activity of our allowance for doubtful accounts for the periods indicated:

	For the Year Ended December 31,		
	2008	2007	2006
Balance at beginning of period	$ 21,659	$ 23,406	$ 37,329
Charges to expense	1,098	2,614	473
Deductions	(7,634)	(4,361)	(14,396)
Balance at end of period	$ 15,123	$ 21,659	$ 23,406

See "Credit Risk Due to Industry Concentrations" in Note 21 for more information.

Cash and Cash Equivalents

Cash and cash equivalents represent unrestricted cash on hand and highly liquid investments with original maturities of less than three months from the date of purchase.

Our Statements of Consolidated Cash Flows are prepared using the indirect method. The indirect method derives net cash flows provided by operating activities by adjusting net income to remove (i) the effects of all deferrals of past operating cash receipts and payments, such as changes during the period in inventory, deferred income and similar transactions, (ii) the effects of all accruals of expected future operating cash receipts and cash payments, such as changes during the period in receivables and payables, (iii) other non-cash amounts such as depreciation, amortization, changes in the fair market value of financial instruments and equity in earnings in unconsolidated affiliates and (iv) the effects of all items classified as investing or financing cash flows, such as proceeds from asset sales and related transactions or extinguishment of debt.

Consolidation Policy

Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest, after the elimination of all material intercompany accounts and transactions. We also consolidate other entities and ventures in which we possess a controlling financial interest as well as partnership interests where we are the sole general partner of the partnership. We evaluate our financial interests in business enterprises to determine if they represent variable interest entities where we are the primary beneficiary. If such criteria are met, we consolidate the financial statements of such businesses with those of our own.

If the entity is organized as a limited partnership or limited liability company and maintains separate ownership accounts, we account for our investment using the equity method if our ownership interest is between 3.0% and 50.0% and we exercise significant influence over the entity's operating and financial policies. For all other types of investments, we apply the equity method of accounting if our ownership interest is between 20.0% and 50.0% and we exercise significant influence over the entity's operating and financial policies. In consolidation we eliminate our proportionate share of profits and losses from transactions with equity method unconsolidated affiliates to the extent such amounts are material and remain on our Consolidated Balance Sheets (or those of our equity method investments) in inventory or similar accounts.

If our ownership interest in an entity does not provide us with either control or significant influence we account for the investment using the cost method. We currently do not have any investments accounted for using the cost method.

Contingencies

Certain conditions may exist as of the date our financial statements are issued, which may result in a loss to us but which will only be resolved when one or more future events occur or fail to occur. Our management and its legal counsel assess such contingent liabilities, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in proceedings, our management and legal counsel evaluate the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

If the assessment of a contingency indicates that it is probable that a material loss has been incurred and the amount of liability can be estimated, then the estimated liability would be accrued in our financial statements. If the assessment indicates that a potentially material loss contingency is not probable but is reasonably possible, or is probable but cannot be estimated, then the nature of the contingent liability, together with an estimate of the range of possible loss (if determinable and material), is disclosed.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed.

Current Assets and Current Liabilities

We present, as individual captions in our Consolidated Balance Sheets, all components of current assets and current liabilities that exceed 5.0% of total current assets and liabilities, respectively.

Deferred Revenues

Amounts billed in advance of the period in which the service is rendered or product delivered are recorded as deferred revenue. At December 31, 2008 and 2007, deferred revenues totaled $107.8 million and $74.4 million, respectively, and were recorded as a component of other current and long-term liabilities, as appropriate, on our Consolidated Balance Sheets. See Note 4 for information regarding our revenue recognition policies.

Earnings Per Unit

Earnings per unit is based on the amount of income allocated to limited partners and the weighted-average number of units outstanding during the period. See Note 19 for additional information regarding our earnings per unit.

Employee Benefit Plans

In 2005, we acquired a controlling ownership interest in Dixie Pipeline Company ("Dixie"), which resulted in Dixie becoming a consolidated subsidiary of ours. Dixie employs the personnel that operate its pipeline system and certain of these employees are eligible to participate in a defined contribution plan and pension and postretirement benefit plans.

Statement of Financial Accounting Standards ("SFAS") 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of SFAS 87, 88, 106, and 132(R), requires businesses to record the over-funded or under-funded status of defined benefit pension and other postretirement plans as an asset or liability at a measurement date and to recognize annual changes in the funded status of each plan through other comprehensive income (loss). At December 31, 2006, Dixie adopted the provisions of SFAS 158. See Note 6 for additional information regarding Dixie's employee benefit plans.

Environmental Costs

Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management's best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals. Expenditures to mitigate or prevent future environmental contamination are capitalized. Ongoing environmental compliance costs are charged to expense as incurred. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. At December 31, 2008, none of our estimated environmental remediation liabilities are discounted to present value since the ultimate amount and timing of cash payments for such liabilities are not readily determinable.

Environmental costs and related accruals were not significant prior to the GulfTerra Merger. As a result of the merger, we assumed an environmental liability for remediation costs associated with mercury gas meters. The balance of this environmental liability was $6.3 million and $17.2 million at December 31, 2008 and 2007, respectively. At December 31, 2008 and 2007, total reserves for environmental liabilities, including those related to the mercury gas meters, were $15.4 million and $26.5 million, respectively. At December 31, 2008 and 2007, $2.8 million and $6.3 million, respectively, of these amounts are classified as current liabilities.

In February 2007, we reserved $6.5 million in cash we received from a third party to fund anticipated environmental remediation costs. These expected costs are associated with assets acquired in connection with the GulfTerra Merger. Previously, the third party had been obligated to indemnify us for such costs. As a result of the settlement, this indemnification arrangement was terminated.

The following table presents the activity of our environmental reserves for the periods indicated:

	For the Year Ended December 31,		
	2008	2007	2006
Balance at beginning of period	$ 26,459	$ 24,178	$ 22,090
Charges to expense	905	375	1,105
Acquisition-related additions and other	--	6,499	8,811
Deductions	(12,002)	(4,593)	(7,828)
Balance at end of period	$ 15,362	$ 26,459	$ 24,178

Equity Awards

See Note 5 for information regarding our accounting for equity awards.

Estimates

Preparing our financial statements in conformity with generally accepted accounting principles in the United States ("GAAP") requires management to make estimates and assumptions that affect amounts presented in the financial statements (i.e. assets, liabilities, revenue and expenses) and disclosures about contingent assets and liabilities. Our actual results could differ from these estimates. On an ongoing basis, management reviews its estimates based on currently available information. Changes in facts and circumstances may result in revised estimates.

We revised the remaining useful lives of certain assets, most notably the assets that constitute our Texas Intrastate System, effective January 1, 2008. This revision adjusted the remaining useful life of such assets to incorporate recent data showing that proved natural gas reserves supporting throughput and processing volumes for these assets have changed since our original determination made in September 2004. These revisions will prospectively reduce our depreciation expense on assets having carrying values totaling $2.72 billion at January 1, 2008. For additional information regarding this change in estimate, see Note 10.

Exchange Contracts

Exchanges are contractual agreements for the movements of NGLs and certain petrochemical products between parties to satisfy timing and logistical needs of the parties. Net exchange volumes borrowed from us under such agreements are valued at market-based prices and included in accounts receivable, and net exchange volumes loaned to us under such agreements are valued at market-based prices and accrued as a liability in accrued product payables.

Receivables and payables arising from exchange transactions are settled with movements of products rather than with cash. When payment or receipt of monetary consideration is required for product differentials and service costs, such items are recognized in our consolidated financial statements on a net basis.

Exit and Disposal Costs

Exit and disposal costs are charges associated with an exit activity not associated with a business combination or with a disposal activity covered by SFAS 144, Accounting for the Impairment or Disposal of Long-Lived Assets. Examples of these costs include (i) termination benefits provided to current employees that are involuntarily terminated under the terms of a benefit arrangement that, in substance, is not an ongoing benefit arrangement or an individual deferred compensation contract, (ii) costs to terminate a contract that is not a capital lease, and (iii) costs to consolidate facilities or relocate employees. In accordance with SFAS 146, Accounting for Costs Associated with Exit and Disposal Activities, we recognize such costs when they are incurred rather than at the date of our commitment to an exit or disposal plan.

Financial Instruments

We use financial instruments such as swaps, forwards and other contracts to manage price risks associated with inventories, firm commitments, interest rates, foreign currency and certain anticipated transactions. We recognize these transactions as assets or liabilities on our Consolidated Balance Sheets based on the instrument's fair value. Fair value is generally defined as the amount at which a financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale.

Changes in fair value of financial instrument contracts are recognized in earnings in the current period (i.e., using mark-to-market accounting) unless specific hedge accounting criteria are met. If the financial instrument meets the criteria of a fair value hedge, gains and losses incurred on the instrument will be recorded in earnings to offset corresponding losses and gains on the hedged item. If the financial instrument meets the criteria of a cash flow hedge, gains and losses incurred on the instrument are recorded in accumulated other comprehensive income (loss), which is generally referred to as "AOCI." Gains and losses on cash flow hedges are reclassified from accumulated other comprehensive income (loss) to earnings when the forecasted transaction occurs or, as appropriate, over the economic life of the hedged item. A contract designated as a hedge of an anticipated transaction that is no longer likely to occur is immediately recognized in earnings.

To qualify for hedge accounting, the item to be hedged must expose us to risk and the related hedging instrument must reduce the exposure and meet the hedging requirements of SFAS 133, Accounting for Derivative Instruments and Hedging Activities (as amended and interpreted). We formally designate the financial instrument as a hedge and document and assess the effectiveness of the hedge at its inception and thereafter on a quarterly basis. Any hedge ineffectiveness is immediately recognized in earnings. See Note 8 for additional information regarding our financial instruments.

Foreign Currency Translation

We own a NGL marketing business located in Canada. The financial statements of this foreign subsidiary are translated into U.S. dollars from the Canadian dollar, which is the subsidiary's functional currency, using the current rate method. Its assets and liabilities are translated at the rate of exchange in effect at the balance sheet date, while revenue and expense items are translated at average rates of exchange during the reporting period. Exchange gains and losses arising from foreign currency translation adjustments are reflected as separate components of accumulated other comprehensive income (loss) in the accompanying Consolidated Balance Sheets. Our net cash flows from this Canadian subsidiary may be adversely affected by changes in foreign currency exchange rates. See Note 7 for information regarding our hedging of currency risk.

Impairment Testing for Goodwill

Our goodwill amounts are assessed for impairment (i) on a routine annual basis or (ii) when impairment indicators are present. If such indicators occur (e.g., the loss of a significant customer, economic obsolescence of plant assets, etc.), the estimated fair value of the reporting unit to which the goodwill is assigned is determined and compared to its book value. If the fair value of the reporting unit exceeds its book value including associated goodwill amounts, the goodwill is considered to be unimpaired and no impairment charge is required. If the fair value of the reporting unit is less than its book value including associated goodwill amounts, a charge to earnings is recorded to reduce the carrying value of the goodwill to its implied fair value. We have not recognized any impairment losses related to goodwill for any of the periods presented. See Note 13 for additional information regarding our goodwill.

Impairment Testing for Long-Lived Assets

Long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable.

Long-lived assets with carrying values that are not expected to be recovered through future cash flows are written-down to their estimated fair values in accordance with SFAS 144. The carrying value of a long-lived asset is deemed not recoverable if it exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset carrying value exceeds the sum of its undiscounted cash flows, a non-cash asset impairment charge equal to the excess of the asset's carrying value over its estimated fair value is recorded. Fair value is defined as the amount at which an asset or liability could be bought or settled in an arm's-length transaction. We measure fair value using market price indicators or, in the absence of such data, appropriate valuation techniques.

We recorded a non-cash asset impairment charge of $0.1 million in 2006, which is reflected as a component of operating costs and expenses in our 2006 Statement of Consolidated Operations. No asset impairment charges were recorded in 2008 and 2007.

Impairment Testing for Unconsolidated Affiliates

We evaluate our equity method investments for impairment when events or changes in circumstances indicate that there is a loss in value of the investment attributable to an other than temporary decline. Examples of such events or changes in circumstances include continuing operating losses of the entity and/or long-term negative changes in the entity's industry. In the event we determine that the loss in value of an investment is other than a temporary decline, we record a charge to earnings to adjust the carrying value of the investment to its estimated fair value.

During 2007, we evaluated our equity method investment in Nemo Gathering Company, LLC ("Nemo") for impairment. As a result of this evaluation, we recorded a $7.0 million non-cash impairment charge that is a component of "Equity in earnings of unconsolidated affiliates" on our Consolidated Statement of Operations for the year ended December 31, 2007. Similarly, during 2006, we evaluated our investment in Neptune Pipeline Company, L.L.C. ("Neptune") for impairment. As a result of this evaluation, we recorded a $7.4 million non-cash impairment charge that is a component of "Equity in earnings of unconsolidated affiliates" on our Consolidated Statement of Operations for the year ended December 31, 2006. We had no such impairment charges during the year ended December 31, 2008. See Note 11 for additional information regarding our equity method investments.

Income Taxes

Provision for income taxes is primarily applicable to our state tax obligations under the Revised Texas Franchise Tax and certain federal and state tax obligations of Seminole Pipeline Company ("Seminole") and Dixie, both of which are consolidated subsidiaries of ours. Deferred income tax assets and liabilities are recognized for temporary differences between the assets and liabilities of our tax paying entities for financial reporting and tax purposes.

In general, legal entities that conduct business in Texas are subject to the Revised Texas Franchise Tax. In May 2006, the State of Texas expanded its pre-existing franchise tax, which applied to corporations and limited liability companies, to include limited partnerships and limited liability partnerships. As a result of the change in tax law, our tax status in the State of Texas changed from non-taxable to taxable.

Since we are structured as a pass-through entity, we are not subject to federal income taxes. As a result, our partners are individually responsible for paying federal income taxes on their share of our taxable income. Since we do not have access to information regarding each partner's tax basis, we cannot readily determine the total difference in the basis of our net assets for financial and tax reporting purposes.

In accordance with Financial Accounting Standards Board Interpretation 48, Accounting for Uncertainty in Income Taxes, we must recognize the tax effects of any uncertain tax positions we may adopt, if the position taken by us is more likely than not sustainable. If a tax position meets such criteria, the tax effect to be recognized by us would be the largest amount of benefit with more than a 50.0% chance of being realized upon settlement. This guidance was effective January 1, 2007, and our adoption of this guidance had no material impact on our financial position, results of operations or cash flows. See Note 18 for additional information regarding our income taxes.

Inventories

Inventories primarily consist of NGLs, certain petrochemical products and natural gas volumes that are valued at the lower of average cost or market. We capitalize, as a cost of inventory, shipping and handling charges directly related to volumes we purchase from third parties or take title to in connection with processing or other agreements. As these volumes are sold and delivered out of inventory, the average cost of these products (including freight-in charges that have been capitalized) are charged to operating costs and expenses. Shipping and handling fees associated with products we sell and deliver to customers are charged to operating costs and expenses as incurred. See Note 9 for additional information regarding our inventories.

Minority Interest

As presented in our Consolidated Balance Sheets, minority interest represents third-party and affiliate ownership interests in the net assets of our consolidated subsidiaries. For financial reporting purposes, the assets and liabilities of our controlled subsidiaries, including Duncan Energy Partners, are consolidated with those of our own, with any third-party or affiliate ownership in such amounts presented as minority interest.

Minority interest, as reflected on our December 31, 2008 and 2007 balance sheets, consists of $281.1 million and $288.6 million, respectively, attributable to third party owners of Duncan Energy Partners and the remainder to our other consolidated affiliates.

Minority interest expense for the year ended December 31, 2008 and 2007 includes $17.3 million and $13.9 million, respectively, attributable to third party owners of Duncan Energy Partners. The remaining minority interest expense amounts for 2008 and 2007 are attributable to our other consolidated affiliates.

Contributions from minority interests for the year ended December 31, 2007 include $290.5 million received from third parties in connection with the initial public offering of Duncan Energy Partners in February 2007.

Natural Gas Imbalances

In the natural gas pipeline transportation business, imbalances frequently result from differences in natural gas volumes received from and delivered to our customers. Such differences occur when a customer delivers more or less gas into our pipelines than is physically redelivered back to them during a particular time period. We have various fee-based agreements with customers to transport their natural gas through our pipelines. Our customers retain ownership of their natural gas shipped through our pipelines. As such, our pipeline transportation activities are not intended to create physical volume differences that would result in significant accounting or economic events for either our customers or us during the course of the arrangement.

We settle pipeline gas imbalances through either (i) physical delivery of in-kind gas or (ii) in cash. These settlements follow contractual guidelines or common industry practices. As imbalances occur, they may be settled (i) on a monthly basis, (ii) at the end of the agreement or (iii) in accordance with industry practice, including negotiated settlements. Certain of our natural gas pipelines have a regulated tariff rate mechanism requiring customer imbalance settlements each month at current market prices.

However, the vast majority of our settlements are through in-kind arrangements whereby incremental volumes are delivered to a customer (in the case of an imbalance payable) or received from a customer (in the case of an imbalance receivable). Such in-kind deliveries are on-going and take place over several periods. In some cases, settlements of imbalances built up over a period of time are ultimately cashed out and are generally negotiated at values which approximate average market prices over a period of time. For those gas imbalances that are ultimately settled over future periods, we estimate the value of such current assets and liabilities using average market prices, which is representative of the estimated value of the imbalances upon final settlement. Changes in natural gas prices may impact our estimates.

At December 31, 2008 and 2007, our natural gas imbalance receivables, net of allowance for doubtful accounts, were $48.4 million and $60.9 million, respectively, and are reflected as a component of "Accounts and notes receivable – trade" on our Consolidated Balance Sheets. At December 31, 2008 and 2007, our imbalance payables were $40.7 million and $38.3 million, respectively, and are reflected as a component of "Accrued product payables" on our Consolidated Balance Sheets.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost. Expenditures for additions, improvements and other enhancements to property, plant and equipment are capitalized and minor replacements, maintenance, and repairs that do not extend asset life or add value are charged to expense as incurred. When property, plant and equipment assets are retired or otherwise disposed of, the related cost and accumulated depreciation is removed from the accounts and any resulting gain or loss is included in the results of operations for the respective period.

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of the assets. Our estimate of depreciation incorporates assumptions regarding the useful economic lives and residual values of our assets. At the time we place our assets in service, we believe such assumptions are reasonable. Under our depreciation policy for midstream energy assets, the remaining economic lives of such assets are limited to the estimated life of the natural resource basins (based on proved reserves at the time of the analysis) from which such assets derive their throughput or processing volumes. Our forecast of the remaining life for the applicable resource basins is based on several factors, including information published by the U.S. Energy Information Administration. Where appropriate, we use other depreciation methods (generally accelerated) for tax purposes.

Leasehold improvements are recorded as a component of property, plant and equipment. The cost of leasehold improvements is charged to earnings using the straight-line method over the shorter of the remaining lease term or the estimated useful lives of the improvements. We consider renewal terms that are deemed reasonably assured when estimating remaining lease terms.

Our assumptions regarding the useful economic lives and residual values of our assets may change in response to new facts and circumstances, which would change our depreciation amounts prospectively. Examples of such circumstances include, but are not limited to, the following: (i) changes in laws and regulations that limit the estimated economic life of an asset; (ii) changes in technology that render an asset obsolete; (iii) changes in expected salvage values; or (iv) significant changes in the forecast life of proved reserves of applicable resource basins, if any. See Note 10 for additional information regarding our property, plant and equipment, including a change in depreciation expense beginning January 1, 2008 resulting from a change in the estimated useful life of certain assets.

Certain of our plant operations entail periodic planned outages for major maintenance activities. These planned shutdowns typically result in significant expenditures, which are principally comprised of amounts paid to third parties for materials, contract services and related items. We use the expense-as-incurred method for our planned major maintenance activities; however, the cost of annual planned major maintenance projects are deferred and recognized ratably over the remaining portion of the calendar year in which such projects occur.

Asset retirement obligations ("AROs") are legal obligations associated with the retirement of tangible long-lived assets that result from their acquisition, construction, development and/or normal operation. When an ARO is incurred, we record a liability for the ARO and capitalize an equal amount as an increase in the carrying value of the related long-lived asset. Over time, the liability is accreted to its present value (accretion expense) and the capitalized amount is depreciated over the remaining useful life of the related long-lived asset. We will incur a gain or loss to the extent that our ARO liabilities are not settled at their recorded amounts.

Restricted Cash

Restricted cash represents amounts held in connection with our commodity financial instruments portfolio and New York Mercantile Exchange ("NYMEX") physical natural gas purchases. Additional cash may be restricted to maintain our positions as commodity prices fluctuate or deposit requirements change. At December 31, 2007, restricted cash also included amounts held by a third party trustee responsible for disbursing proceeds from our Petal GO Zone bond offering. During 2008, virtually all proceeds from the Petal GO Zone bonds were released by the trustee to fund construction costs associated with the expansion of our Petal, Mississippi storage facility. The following table presents the components of our restricted cash balances at the periods indicated:

	At December 31,	
	2008	2007
Amounts held in brokerage accounts related to commodity hedging activities and physical natural gas purchases	$ 203,789	$ 53,144
Proceeds from Petal GO Zone bonds reserved for construction costs	1	17,871
Total restricted cash	$ 203,790	$ 71,015

Revenue Recognition

See Note 4 for information regarding our revenue recognition policies.

Start-Up and Organization Costs

Start-up costs and organization costs are expensed as incurred. Start-up costs are defined as one-time activities related to opening a new facility, introducing a new product or service, conducting activities in a new territory, pursuing a new class of customer, initiating a new process in an existing facility or some new operation. Routine ongoing efforts to improve existing facilities, products or services are not considered start-up costs. Organization costs include legal fees, promotional costs and similar charges incurred in connection with the formation of a business.

Note 3. Recent Accounting Developments

The accounting standard setting bodies have recently issued the following accounting guidance that will affect our future financial statements: SFAS 141(R), Business Combinations; FASB Staff Position ("FSP") SFAS 142-3, Determination of the Useful Life of Intangible Assets; SFAS 157, Fair Value Measurements; SFAS 160, Noncontrolling Interests in Consolidated Financial Statements – An amendment of ARB 51; SFAS 161, Disclosures about Derivative Instruments and Hedging Activities – An Amendment of SFAS 133; Emerging Issues Task Force ("EITF") 08-6, Equity Method Investment Accounting Considerations; and EITF 07-4, Application of the Two Class Method Under SFAS 128, Earnings Per Share, to Master Limited Partnerships ("MLPs").

SFAS 141(R), Business Combinations. SFAS 141(R) replaces SFAS 141, Business Combinations and was effective January 1, 2009. SFAS 141(R) retains the fundamental requirements of SFAS 141 in that the acquisition method of accounting (previously termed the "purchase method") be used for all business combinations and for the "acquirer" to be identified in each business combination. SFAS 141(R) defines the acquirer as the entity that obtains control of one or more businesses in a business combination and establishes the acquisition date as the date that the acquirer achieves control. This new guidance also retains guidance in SFAS 141 for identifying and recognizing intangible assets separately from goodwill. SFAS 141(R) will have an impact on the way in which we evaluate acquisitions.

The objective of SFAS 141(R) is to improve the relevance, representational faithfulness, and comparability of the information a reporting entity provides in its financial reports about business combinations and their effects. To accomplish this, SFAS 141(R) establishes principles and requirements for how the acquirer:

- Recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interests in the acquiree.

- Recognizes and measures any goodwill acquired in the business combination or a gain resulting from a bargain purchase. SFAS 141(R) defines a bargain purchase as a business combination in which the total acquisition-date fair value of the identifiable net assets acquired exceeds the fair value of the consideration transferred plus any noncontrolling interest in the acquiree, and requires the acquirer to recognize that excess in net income as a gain attributable to the acquirer.

- Determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination.

SFAS 141(R) also requires that direct costs of an acquisition (e.g. finder's fees, outside consultants, etc.) be expensed as incurred and not capitalized as part of the purchase price.

FSP FAS 142-3, Determination of the Useful Life of Intangible Assets. FSP 142-3 revised the factors that should be considered in developing renewal or extension assumptions used in determining the useful life of recognized intangible assets under SFAS 142, Goodwill and Other Intangible Assets. These revisions are intended to improve consistency between the useful life of a recognized intangible asset under SFAS 142 and the period of expected cash flows used to measure the fair value of such assets under SFAS 141(R) and other accounting guidance. The measurement and disclosure requirements of this new guidance will be applied to intangible assets acquired after January 1, 2009. Our adoption of this guidance is not expected to have a material impact on our consolidated financial statements.

SFAS 157, Fair Value Measurements. SFAS 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. Although certain provisions of SFAS 157 were effective January 1, 2008, the remaining guidance of this new standard applicable to nonfinancial assets and liabilities was effective January 1, 2009. See Note 7 for information regarding fair value-related disclosures required for 2008 in connection with SFAS 157.

SFAS 157 applies to fair-value measurements that are already required (or permitted) by other accounting standards and is expected to increase the consistency of those measurements. SFAS 157 emphasizes that fair value is a market-based measurement that should be determined based on the assumptions that market participants would use in pricing an asset or liability. Companies are required to disclose the extent to which fair value is used to measure assets and liabilities, the inputs used to develop such measurements, and the effect of certain of the measurements on earnings (or changes in net assets) during a period. Our adoption of this guidance is not expected to have a material impact on our consolidated financial statements. SFAS 157 will impact the valuation of assets and liabilities (and related disclosures) in connection with future business combinations and impairment testing.

SFAS 160, Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB 51. SFAS 160 established accounting and reporting standards for noncontrolling interests, which have been referred to as minority interests in prior accounting literature. SFAS 160 was effective January 1, 2009. A noncontrolling interest is that portion of equity in a consolidated subsidiary not attributable, directly or indirectly, to a reporting entity. This new standard requires, among other things, that (i) ownership interests of noncontrolling interests be presented as a component of equity on the balance sheet (i.e., elimination of the "mezzanine" presentation); (ii) elimination of minority interest expense as a line item on the statement of income and, as a result, that net income be allocated between the reporting entity and noncontrolling interests on the face of the statement of income; and (iii) enhanced disclosures regarding noncontrolling interests.

SFAS 160 will affect the presentation of minority interest on our financial statements beginning with the first quarter of 2009. Minority interest in the net assets of our consolidated subsidiaries will be presented as a component of partners' equity on our Consolidated Balance Sheets. With respect to our Statements of Consolidated Operations, net income and comprehensive income will be allocated between minority interests and us, as applicable.

SFAS 161, Disclosures about Derivative Instruments and Hedging Activities - An Amendment of SFAS 133. SFAS 161 revised the disclosure requirements for financial instruments and related hedging activities to provide users of financial statements with an enhanced understanding of (i) why and how an entity uses financial instruments, (ii) how an entity accounts for financial instruments and related hedged items under SFAS 133, Accounting for Derivative Instruments and Hedging Activities (including related interpretations), and (iii) how financial instruments and related hedged items affect an entity's financial position, financial performance, and cash flows.

SFAS 161 requires qualitative disclosures about objectives and strategies for using financial instruments, quantitative disclosures about fair value amounts of and gains and losses on financial instruments, and disclosures about credit risk-related contingent features in financial instrument agreements. SFAS 161 was effective January 1, 2009 and we will apply its requirements beginning with the first quarter of 2009.

EITF 08-6, Equity Method Investment Accounting Considerations. EITF 08-6 clarifies the accounting for certain transactions and impairment considerations involving equity method investments under SFAS 141(R) and SFAS 160. EITF 08-6 generally requires that (i) transaction costs should be included in the initial carrying value of an equity method investment; (ii) an equity method investor shall not test separately an investee's underlying assets for impairment, rather such testing should be performed in accordance with Opinion 18 (i.e., on the equity method investment itself); (iii) an equity method investor shall account for a share issuance by an investee as if the investor had sold a proportionate share of its investment (any gain or loss to the investor resulting from the investee's share issuance shall be recognized in earnings); and (iv) a gain or loss should not be recognized when changing the method of accounting for an investment from the equity method to the cost method. EITF 08-6 was effective January 1, 2009.

EITF 07-4, Application of the Two Class Method Under SFAS 128, Earnings Per Share, to MLPs. EITF 07-4 prescribes the manner in which a MLP should allocate and present earnings per unit using the two-class method set forth in SFAS 128, Earnings Per Share. Under the two-class method, current period earnings are allocated to the general partner (including earnings attributable to any embedded incentive distribution rights ("IDRs")) and limited partners according to the distribution formula for available cash set forth in the MLP's partnership agreement. EITF 07-4 was effective for us on January 1, 2009. Our adoption of EITF 07-4 did not have a material impact on our earnings per unit computations and disclosures.

Note 4. Revenue Recognition

In general, we recognize revenue from our customers when all of the following criteria are met: (i) persuasive evidence of an exchange arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the buyer's price is fixed or determinable and (iv) collectability is reasonably assured. The following information provides a general description our underlying revenue recognition policies by business segment:

NGL Pipelines & Services

This aspect of our business generates revenues primarily from the provision of natural gas processing, NGL pipeline transportation, product storage and NGL fractionation services and the sale of NGLs. In our natural gas processing activities, we enter into margin-band contracts, percent-of-liquids contracts, percent-of-proceeds contracts, fee-based contracts, hybrid-contracts (i.e. mixed percent-of-liquids and fee-based) and keepwhole contracts. Under margin-band and keepwhole contracts, we take ownership of mixed NGLs extracted from the producer's natural gas stream and recognize revenue when the extracted NGLs are delivered and sold to customers under NGL marketing sales contracts. In the same way, revenue is recognized under our percent-of-liquids contracts except that the volume of NGLs we extract and sell is less than the total amount of NGLs extracted from the producers' natural gas. Under a percent-of-liquids contract, the producer retains title to the remaining percentage of mixed NGLs we extract. Under a percent-of-proceeds contract, we share in the proceeds generated from the sale of the mixed NGLs we extract on the producer's behalf. If a cash fee for natural gas processing services is stipulated by the contract, we record revenue when the natural gas has been processed and delivered to the producer.

Our NGL marketing activities generate revenues from the sale of NGLs obtained from either our natural gas processing activities or purchased from third parties on the open market. Revenues from these sales contracts are recognized when the NGLs are delivered to customers. In general, the sales prices referenced in these contracts are market-related and can include pricing differentials for such factors as delivery location.

Under our NGL pipeline transportation contracts and tariffs, revenue is recognized when volumes have been delivered to customers. Revenue from these contracts and tariffs is generally based upon a fixed fee per gallon of liquids transported multiplied by the volume delivered. Transportation fees charged under these arrangements are either contractual or regulated by governmental agencies such as the Federal Energy Regulatory Commission ("FERC").

We collect storage revenues under our NGL and related product storage contracts based on the number of days a customer has volumes in storage multiplied by a storage rate (as defined in each contract). Under these contracts, revenue is recognized ratably over the length of the storage period. With respect to capacity reservation agreements, we collect a fee for reserving storage capacity for customers in our underground storage wells. Under these agreements, revenue is recognized ratably over the specified reservation period. Excess storage fees are collected when customers exceed their reservation amounts and are recognized in the period of occurrence.

Revenues from product terminalling activities (applicable to our import and export operations) are recorded in the period such services are provided. Customers are typically billed a fee per unit of volume loaded or unloaded. With respect to export operations, revenues may also include demand payments charged to customers who reserve the use of our export facilities and later fail to use them. Demand fee revenues are recognized when the customer fails to utilize the specified export facility as required by contract.

We enter into fee-based arrangements and percent-of-liquids contracts for the NGL fractionation services we provide to customers. Under such fee-based arrangements, revenue is recognized in the period services are provided. Such fee-based arrangements typically include a base-processing fee (typically in cents per gallon) that is subject to adjustment for changes in certain fractionation expenses (e.g. natural gas fuel costs). Certain of our NGL fractionation facilities generate revenues using percent-of-liquids contracts. Such contracts allow us to retain a contractually determined percentage of the customer's fractionated NGL products as payment for services rendered. Revenue is recognized from such arrangements when we sell and deliver the retained NGLs to customers.

Onshore Natural Gas Pipelines & Services

This aspect of our business generates revenues primarily from the provision of natural gas pipeline transportation and gathering services; natural gas storage services; and from the sale of natural gas. Certain of our onshore natural gas pipelines generate revenues from transportation and gathering agreements as customers are billed a fee per unit of volume multiplied by the volume delivered or gathered. Fees charged under these arrangements are either contractual or regulated by governmental agencies such as the FERC. Revenues associated with these fee-based contracts are recognized when volumes have been delivered.

Revenues from natural gas storage contracts typically have two components: (i) a monthly demand payment, which is associated with storage capacity reservations, and (ii) a storage fee per unit of volume held at each location. Revenues from demand payments are recognized during the period the customer reserves capacity. Revenues from storage fees are recognized in the period the services are provided.

Our natural gas marketing activities generate revenues from the sale of natural gas purchased from third parties on the open market. Revenues from these sales contracts are recognized when the natural gas is delivered to customers. In general, the sales prices referenced in these contracts are market-related and can include pricing differentials for such factors as delivery location.

Offshore Pipelines & Services

This aspect of our business generates revenues from the provision of offshore natural gas and crude oil pipeline transportation services and related offshore platform operations. Our offshore natural gas pipelines generate revenues through fee-based contracts or tariffs where revenues are equal to the product of a fee per unit of volume (typically in million British thermal units) multiplied by the volume of natural gas transported. Revenues associated with these fee-based contracts and tariffs are recognized when natural gas volumes have been delivered.

The majority of revenues from our offshore crude oil pipelines are generated based upon a transportation fee per unit of volume (typically in barrels) multiplied by the volume delivered to the customer. A substantial portion of the revenues generated by our offshore crude oil pipeline systems are attributable to long-term transportation agreements with producers. The revenues we earn for our services are dependent on the volume of crude oil to be delivered and the level of fees charged to customers.

Revenues from offshore platform services generally consist of demand payments and commodity charges. Revenues from platform services are recognized in the period the services are provided. Demand fees represent charges to customers served by our offshore platforms regardless of the volume the customer delivers to the platform. Revenues from commodity charges are based on a fixed-fee per unit of volume delivered to the platform (typically per million cubic feet of natural gas or per barrel of crude oil) multiplied by the total volume of each product delivered. Contracts for platform services often include both demand payments and commodity charges, but demand payments generally expire after a contractually fixed period of time and in some instances may be subject to cancellation by customers. Our Independence Hub and Marco Polo offshore platforms earn a significant amount of demand revenues. The Independence Hub platform will earn $54.6 million of demand revenues annually through March 2012. The Marco Polo platform will earn $2.1 million of demand revenues monthly through March 2009.

Petrochemical Services

This aspect of our business generates revenues from the provision of isomerization and propylene fractionation services and the sale of certain petrochemical products. Our isomerization and propylene fractionation operations generate revenues through fee-based arrangements, which typically include a base-processing fee per gallon (or other unit of measurement) subject to adjustment for changes in natural gas, electricity and labor costs, which are the primary costs of propylene fractionation and isomerization operations. Revenues resulting from such agreements are recognized in the period the services are provided.

Our petrochemical marketing activities generate revenues from the sale of propylene and other petrochemicals obtained from either its processing activities or purchased from third parties on the open market. Revenues from these sales contracts are recognized when the petrochemicals are delivered to customers. In general, the sales prices referenced in these contracts are market-related and can include pricing differentials for such factors as delivery location.

Note 5. Accounting for Equity Awards

We account for equity awards in accordance with SFAS 123(R), Share-Based Payment. SFAS 123(R) requires us to recognize compensation expense related to equity awards based on the fair value of the award at grant date. The fair value of restricted unit awards is based on the market price of the underlying common units on the date of grant. The fair value of other equity awards is estimated using the Black-Scholes option pricing model. The fair value of an equity-classified award (such as a restricted unit award) is amortized to earnings on a straight-line basis over the requisite service or vesting period. Compensation expense for liability-classified awards (such as unit appreciation rights ("UARs")) is recognized over the requisite service or vesting period of an award based on the fair value of the award remeasured at each reporting period. Liability-classified awards are settled in cash upon vesting.

As used in the context of the EPCO plans, the term "restricted unit" represents a time-vested unit under SFAS 123(R). Such awards are non-vested until the required service period expires.

Upon our adoption of SFAS 123(R), we recognized, as a benefit, a cumulative effect of a change in accounting principle of $1.5 million based on the SFAS 123(R) requirement to recognize compensation expense based upon the grant date fair value of an equity award and the application of an estimated forfeiture rate to unvested awards. In addition, previously recognized deferred compensation expense of $14.6 million related to our restricted common units was reversed on January 1, 2006.

Prior to our adoption of SFAS 123(R), we did not recognize any compensation expense related to unit options; however, compensation expense was recognized in connection with awards granted by EPE Unit I and the issuance of restricted units. The effects of applying SFAS 123(R) during the year ended December 31, 2006 did not have a material effect on our net income or basic and diluted earnings per unit. Since we adopted SFAS 123(R) using the modified prospective method, we have not restated the financial statements of prior periods to reflect this new standard.

The following table summarizes our equity compensation amounts by plan during each of the periods indicated:

	For the Year Ended December 31,		
	2008	**2007**	**2006**
EPCO 1998 Long-Term Incentive Plan ("EPCO 1998 Plan")			
Unit options	$ 439	$ 4,447	$ 701
Restricted units	8,816	7,721	5,019
Total EPCO 1998 Plan (1)	9,255	12,168	5,720
Enterprise Products 2008 Long-Term Incentive Plan ("EPD 2008 LTIP")			
Unit options	87	--	--
Total EPD 2008 LTIP	87	--	--
Employee Partnerships	5,535	3,911	2,146
DEP GP UARs	1	69	--
Total compensation expense	$ 14,878	$ 16,148	$ 7,866

(1) Amounts for the year ended December 31, 2007 include $4.6 million associated with the resignation of our general partner's former chief executive officer.

EPCO 1998 Plan

Unit option awards. Under the EPCO 1998 Plan, non-qualified incentive options to purchase a fixed number of our common units may be granted to key employees of EPCO who perform management, administrative or operational functions for us. When issued, the exercise price of each option grant is equivalent to the market price of the underlying equity on the date of grant. During 2008, in response to changes in the federal tax code applicable to certain types of equity awards, we amended the terms of certain of our outstanding unit options. In general, the expiration dates of these awards were modified from May and August 2017 to December 2012.

In order to fund its obligations under the EPCO 1998 Plan, EPCO may purchase common units at fair value either in the open market or directly from us. When employees exercise unit options, we reimburse EPCO for the cash difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the units issued to the employee.

The fair value of each unit option is estimated on the date of grant using the Black-Scholes option pricing model, which incorporates various assumptions including expected life of the options, risk-free interest rates, expected distribution yield on our common units, and expected unit price volatility of our common units. In general, our assumption of expected life of the options represents the period of time that the options are expected to be outstanding based on an analysis of historical option activity. Our selection of the risk-free interest rate is based on published yields for U.S. government securities with comparable terms. The expected distribution yield and unit price volatility is estimated based on several factors, which include an analysis of our historical unit price volatility and distribution yield over a period equal to the expected life of the option.

The EPCO 1998 Plan provides for the issuance of up to 7,000,000 of our common units. After giving effect to outstanding option awards at December 31, 2008 and the issuance and forfeiture of restricted unit awards through December 31, 2008, a total of 814,674 additional common units could be issued under the EPCO 1998 Plan.

The following table presents option activity under the EPCO 1998 Plan for the periods indicated:

	Number of Units	**Weighted-Average Strike Price (dollars/unit)**	**Weighted-Average Remaining Contractual Term (in years)**	**Aggregate Intrinsic Value** (1)
Outstanding at December 31, 2005	2,082,000	$ 22.16		
Granted (2)	590,000	24.85		
Exercised	(211,000)	15.95		
Forfeited	(45,000)	24.28		
Outstanding at December 31, 2006	2,416,000	23.32		
Granted (3)	895,000	30.63		
Exercised	(256,000)	19.26		
Settled or forfeited (4)	(740,000)	24.62		
Outstanding at December 31, 2007 (5)	2,315,000	26.18		
Exercised	(61,500)	20.38		
Forfeited	(85,000)	26.72		
Outstanding at December 31, 2008 (6)	2,168,500	26.32	5.19	$ --
Options exercisable at:				
December 31, 2006	591,000	$ 20.85	5.11	$ 4,808
December 31, 2007	335,000	$ 22.06	3.96	$ 3,291
December 31, 2008 (6)	548,500	$ 21.47	4.08	$ --

(1) Aggregate intrinsic value reflects fully vested unit options at the date indicated.
(2) The total grant date fair value of these awards was $1.2 million based on the following assumptions: (i) weighted-average expected life of options of seven years; (ii) weighted-average risk-free interest rate of 5.0%; (iii) weighted-average expected distribution yield on our common units of 8.9%; and (iv) weighted-average expected unit price volatility on our common units of 23.5%.
(3) The total grant date fair value of these awards was $2.4 million based on the following assumptions: (i) expected life of options of seven years; (ii) weighted-average risk-free interest rate of 4.8%; (iii) weighted-average expected distribution yield on our common units of 8.4%; and (iv) weighted-average expected unit price volatility on our common units of 23.2%.
(4) Includes the settlement of 710,000 options in connection with the resignation of our general partner's former chief executive officer.
(5) During 2008, we amended the terms of certain of our outstanding unit options. In general, the expiration dates of these awards were modified from May and August 2017 to December 2012.
(6) We were committed to issue 2,168,500 and 2,315,000 of our common units at December 31, 2008 and 2007, respectively, if all outstanding options awarded under the EPCO 1998 Plan (as of these dates) were exercised. An additional 365,000, 480,000 and 775,000 of these options are exercisable in 2009, 2010 and 2012, respectively.

The total intrinsic value of option awards exercised during the years ended December 31, 2008, 2007 and 2006 were $0.6 million, $3.0 million and $2.2 million, respectively. At December 31, 2008, there was an estimated $1.7 million of total unrecognized compensation cost related to nonvested unit option awards granted under the EPCO 1998 Plan. We expect to recognize this cost over a weighted-average period of 2.1 years. We will recognize our share of these costs in accordance with the EPCO administrative services agreement (the "ASA") (see Note 17).

During the years ended December 31, 2008 and 2007, we received cash of $0.7 million and $7.5 million, respectively, from the exercise of option awards granted under the EPCO 1998 Plan. Conversely, our option-related reimbursements to EPCO were $0.6 million and $3.0 million, respectively.

Restricted unit awards. Under the EPCO 1998 Plan, we may also issue restricted common units to key employees of EPCO and directors of our general partner. In general, the restricted unit awards allow recipients to acquire the underlying common units at no cost to the recipient once a defined cliff vesting period expires, subject to certain forfeiture provisions. The restrictions on such units generally lapse four years from the date of grant. Compensation expense is recognized on a straight-line basis over the vesting period. Fair value of such restricted units is based on the market price of the underlying common units on the date of grant and an allowance for estimated forfeitures.

Each recipient is also entitled to cash distributions equal to the product of the number of restricted units outstanding for the participant and the cash distribution per unit paid by us to our unitholders. Since restricted units are issued securities, such distributions are reflected as a component of cash distributions to partners as shown on our Statements of Consolidated Cash Flows. We paid $3.9 million, $2.6 million and $1.6 million in cash distributions with respect to restricted units during the years ended December 31, 2008, 2007 and 2006, respectively.

The following table summarizes information regarding our restricted unit awards for the periods indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted units at December 31, 2005	751,604	
Granted (2)	466,400	$ 25.21
Vested	(42,136)	$ 24.02
Forfeited	(70,631)	$ 22.86
Restricted units at December 31, 2006	1,105,237	
Granted (3)	738,040	$ 25.61
Vested	(4,884)	$ 25.28
Forfeited	(36,800)	$ 23.51
Settled (4)	(113,053)	$ 23.24
Restricted units at December 31, 2007	1,688,540	
Granted (5)	766,200	$ 24.93
Vested	(285,363)	$ 23.11
Forfeited	(88,777)	$ 26.98
Restricted units at December 31, 2008	2,080,600	

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued. The weighted-average grant date fair value per unit for forfeited and vested awards is determined before an allowance for forfeitures.

(2) Aggregate grant date fair value of restricted unit awards issued during 2006 was $10.8 million based on grant date market prices of our common units ranging from $24.85 to $27.45 per unit and estimated forfeiture rates ranging from 7.8% to 9.8%.

(3) Aggregate grant date fair value of restricted unit awards issued during 2007 was $18.9 million based on grant date market prices of our common units ranging from $28.00 to $31.83 per unit and estimated forfeiture rates ranging from 4.6% to 17.0%.

(4) Reflects the settlement of restricted units in connection with the resignation of our general partner's former chief executive officer.

(5) Aggregate grant date fair value of restricted unit awards issued during 2008 was $19.1 million based on grant date market prices of our common units ranging from $25.00 to $32.31 per unit and an estimated forfeiture rate of 17.0%.

The total fair value of restricted unit awards that vested during the year ended December 31, 2008 was $6.6 million. At December 31, 2008, there was an estimated $31.5 million of total unrecognized compensation cost related to restricted unit awards granted under the EPCO 1998 Plan, which we expect to recognize over a weighted-average period of 2.3 years. We will recognize our share of such costs in accordance with the ASA.

Phantom unit awards. The EPCO 1998 Plan also provides for the issuance of phantom unit awards. These liability awards are automatically redeemed for cash based on the vested portion of the fair market value of the phantom units at redemption dates in each award. The fair market value of each phantom unit award is equal to the market closing price of our common units on the redemption date. Each participant is required to redeem their phantom units as they vest, which typically is four years from the date the award is granted. No phantom unit awards have been issued to date under the EPCO 1998 Plan.

The EPCO 1998 Plan also provides for the award of distribution equivalent rights ("DERs") in tandem with its phantom unit awards. A DER entitles the participant to cash distributions equal to the product of the number of phantom units outstanding for the participant and the cash distribution rate paid by us to our unitholders. No DERs have been issued as of December 31, 2008 under the EPCO 1998 Plan.

EPD 2008 LTIP

On January 29, 2008, our unitholders approved the EPD 2008 LTIP, which provides for awards of our common units and other rights to our non-employee directors and to consultants and employees of EPCO and its affiliates providing services to us. Awards under the EPD 2008 LTIP may be granted in the form of unit options, restricted units, phantom units, UARs and DERs. The EPD 2008 LTIP is administered by EPGP's Audit, Conflicts and Governance ("ACG") Committee. The EPD 2008 LTIP provides for the issuance of up to 10,000,000 of our common units. After giving effect to option awards outstanding at December 31, 2008, a total of 9,205,000 additional common units could be issued under the EPD 2008 LTIP.

The EPD 2008 LTIP may be amended or terminated at any time by the Board of Directors of EPCO or EPGP's ACG Committee; however, the rules of the NYSE require that any material amendment, such as a significant increase in the number of common units available under the plan or a change in the types of awards available under the plan, would require the approval of our unitholders. The ACG Committee is also authorized to make adjustments in the terms and conditions of, and the criteria included in, awards under the plan in specified circumstances. The EPD 2008 LTIP is effective until the earlier of January 29, 2018 or the time which all available units under the incentive plan have been delivered to participants or the time of termination of the plan by EPCO or EPGP's ACG Committee.

Unit option awards. The exercise price of unit options awarded to participants is determined by the ACG Committee (at its discretion) at the date of grant and may be no less than the fair market value of our common units at the date of grant. The following table presents unit option activity under the EPD 2008 LTIP for the periods indicated:

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)
Outstanding at January 1, 2008	--		
Granted (1)	795,000	$ 30.93	
Outstanding at December 31, 2008 (2)	795,000	$ 30.93	5.00

(1) Aggregate grant date fair value of these unit options issued during 2008 was $1.6 million based on the following assumptions: (i) a grant date market price of our common units of $30.93 per unit; (ii) expected life of options of 4.7 years; (iii) risk-free interest rate of 3.3%; (iv) expected distribution yield on our common units of 7.0%; (v) expected unit price volatility on our common units of 19.8%; and (vi) an estimated forfeiture rate of 17.0%.

(2) The 795,000 units outstanding at December 31, 2008 will become exercisable in 2013.

At December 31, 2008, there was an estimated $1.3 million of total unrecognized compensation cost related to nonvested unit options granted under the EPD 2008 LTIP. We expect to recognize our share of this cost over a remaining period of 3.4 years in accordance with the ASA.

Phantom unit awards. The EPD 2008 LTIP also provides for the issuance of phantom unit awards. These liability awards are automatically redeemed for cash based on the vested portion of the fair market value of the phantom units at redemption dates in each award. The fair market value of each phantom unit award is equal to the market closing price of our common units on the redemption date. Each participant is required to redeem their phantom units as they vest, which typically is three years from the date the award is granted. There were a total of 4,400 phantom units granted under the EPD 2008 LTIP during the fourth quarter of 2008 and outstanding at December 31, 2008. These awards cliff vest in 2011. At December 31, 2008, we had an accrued liability of $5 thousand for compensation related to these phantom unit awards.

Employee Partnerships

As long-term incentive arrangements, EPCO has granted its key employees who perform services on behalf of us, EPCO and other affiliated companies, “profits interests” in five limited partnerships. The employees were issued Class B limited partner interests and admitted as Class B limited partners in the Employee Partnerships without capital contributions. As discussed and defined above, the Employee Partnerships are: EPE Unit I; EPE Unit II; EPE Unit III; Enterprise Unit; and EPCO Unit. Enterprise Unit and EPCO Unit were formed in 2008.

The Class B limited partner interests entitle each holder to participate in the appreciation in value of the publicly traded limited partner units owned by the underlying Employee Partnership. The Employee Partnerships own either Enterprise GP Holdings units (“EPE units”) or Enterprise Products Partners’ common units (“EPD units”) or both. The Class B limited partner interests are subject to forfeiture if the participating employee’s employment with EPCO is terminated prior to vesting, with customary exceptions for death, disability and certain retirements and upon certain change of control events.

We account for the profits interest awards under SFAS 123(R). As a result, the compensation expense attributable to these awards is based on the estimated grant date fair value of each award. An allocated portion of the fair value of these equity-based awards is charged to us under the ASA (see Note 17). We are not responsible for reimbursing EPCO for any expenses of the Employee Partnerships, including the value of any contributions of cash or limited partner units made by private company affiliates of EPCO at the formation of each Employee Partnership. However, pursuant to the ASA, beginning in February 2009 we will reimburse EPCO for our allocated share of distributions of cash or securities made to the Class B limited partners of EPCO Unit.

Each Employee Partnership has a single Class A limited partner, which is a privately-held indirect subsidiary of EPCO, and a varying number of Class B limited partners. At formation, the Class A limited partner either contributes cash or limited partner units it owns to the Employee Partnership. If cash is contributed, the Employee Partnership uses these funds to acquire limited partner units on the open market. In general, the Class A limited partner earns a preferred return (either fixed or variable depending on the partnership agreement) on its investment (“Capital Base”) in the Employee Partnership and any residual quarterly cash amounts, if any, are distributed to the Class B limited partners. Upon liquidation, Employee Partnership assets having a fair market value equal to the Class A limited partner’s Capital Base, plus any preferred return for the period in which liquidation occurs, will be distributed to the Class A limited partner. Any remaining assets will be distributed to the Class B limited partner(s) as a residual profits interest.

The following table summarizes key elements of each Employee Partnership as of December 31, 2008:

Employee Partnership	Description of Assets	Initial Class A Capital Base	Class A Partner Preferred Return	Award Vesting Date (1)	Grant Date Fair Value of Awards (2)	Unrecognized Compensation Cost (3)
EPE Unit I	1,821,428 EPE units	$51.0 million	4.50% to 5.725% (4)	November 2012	$17.0 million	$9.3 million
EPE Unit II	40,725 EPE units	$1.5 million	4.50% to 5.725% (4)	February 2014	$0.3 million	$0.2 million
EPE Unit III	4,421,326 EPE units	$170.0 million	3.80%	May 2014	$32.7 million	$25.1 million
Enterprise Unit	881,836 EPE units 844,552 EPD units	$51.5 million	5.00%	February 2014	$4.2 million	$3.7 million
EPCO Unit	779,102 EPD units	$17.0 million	4.87%	November 2013	$7.2 million	$7.0 million

(1) The vesting date may be accelerated for change of control and other events as described in the underlying partnership agreements.
(2) Our estimated grant date fair values were determined using a Black-Scholes option pricing model and reflect adjustments for forfeitures, regrants and other modifications. See following table for information regarding our fair value assumptions.
(3) Unrecognized compensation cost represents the total future expense to be recognized by the EPCO group of companies as of December 31, 2008. We will recognize our allocated share of such costs in the future. The period over which the unrecognized compensation cost will be recognized is as follows for each Employee Partnership: 3.9 years, EPE Unit I; 5.1 years, EPE Unit II; 5.4 years, EPE Unit III; 5.1 years, Enterprise Unit; and 4.9 years, EPCO Unit.
(4) In July 2008, the Class A preferred return was reduced from 6.25% to the floating amounts presented.

The following table summarizes the assumptions we used in deriving the estimated grant date fair value for each of the Employee Partnerships using a Black-Scholes option pricing model:

Employee Partnership	Expected Life of Award	Risk-Free Interest Rate	Expected Distribution Yield of EPE/EPD units	Expected Unit Price Volatility of EPE/EPD units
EPE Unit I	3 to 5 years	2.7% to 5.0%	3.0% to 4.8%	16.6% to 30.0%
EPE Unit II	5 to 6 years	3.3% to 4.4%	3.8% to 4.8%	18.7% to 19.4%
EPE Unit III	4 to 6 years	3.2% to 4.9%	4.0% to 4.8%	16.6% to 19.4%
Enterprise Unit	6 years	2.7% to 3.9%	4.5% to 8.0%	15.3% to 22.1%
EPCO Unit	5 years	2.4%	11.1%	50.0%

DEP GP UARs

The non-employee directors of DEP GP, the general partner of Duncan Energy Partners, have been granted UARs in the form of letter agreements. These liability awards are not part of any established long-term incentive plan of EPCO, Enterprise GP Holdings, Duncan Energy Partners or us. The compensation expense associated with these awards is recognized by DEP GP, which is our consolidated subsidiary. These UARs entitle each non-employee director to receive a cash payment on the vesting date equal to the excess, if any, of the fair market value of Enterprise GP Holdings' units (determined as of a future vesting date) over the grant date fair value. If a director resigns prior to vesting, his UAR awards are forfeited. These UARs are accounted for similar to liability awards under SFAS 123(R) since they will be settled with cash.

As of December 31, 2008, a total of 90,000 UARs had been granted to non-employee directors of DEP GP that cliff vest in 2012. If a director resigns prior to vesting, his UAR awards are forfeited. The grant date fair value with respect to these UARs is based on an Enterprise GP Holdings' unit price of $36.68.

Note 6. Employee Benefit Plans

Dixie employs the personnel that operate its pipeline system and certain of these employees are eligible to participate in a defined contribution plan and pension and postretirement benefit plans. Due to the immaterial nature of Dixie's employee benefit plans to our consolidated financial position, results of operations and cash flows, our discussion is limited to the following:

Defined Contribution Plan

Dixie contributed $0.3 million to its company-sponsored defined contribution plan for each of the years ended December 31, 2008 and 2007.

Pension and Postretirement Benefit Plans

Dixie's pension plan is a noncontributory defined benefit plan that provides for the payment of benefits to retirees based on their age at retirement, years of service and average compensation. Dixie's postretirement benefit plan also provides medical and life insurance to retired employees. The medical plan is contributory and the life insurance plan is noncontributory. Dixie employees hired after July 1, 2004 are not eligible for pension and other benefit plans after retirement.

The following table presents Dixie's benefit obligations, fair value of plan assets and funded status at December 31, 2008.

	Pension Plan	Postretirement Plan
Projected benefit obligation	$ 7,733	$ 4,976
Accumulated benefit obligation	5,711	--
Fair value of plan assets	4,035	--
Funded status	(3,698)	(4,976)

Projected benefit obligations and net periodic benefit costs are based on actuarial estimates and assumptions. The weighted-average actuarial assumptions used in determining the projected benefit obligation at December 31, 2008 were as follows: discount rate of 6.4%; rate of compensation increase of 4.0% for both the pension and postretirement plans; and a medical trend rate of 8.5% for 2009 grading to an ultimate trend of 5.0% for 2015 and later years. Dixie's net pension and postretirement benefit costs for 2008 were $0.6 million and $0.4 million, respectively. Dixie's net pension and postretirement benefit costs for 2007 were $1.1 million (including settlement loss of $0.6 million) and $0.4 million, respectively.

Future benefits expected to be paid from Dixie's pension and postretirement plans are as follows for the periods indicated:

	Pension Plan	Postretirement Plan
2009	$ 289	$ 357
2010	334	399
2011	535	427
2012	408	440
2013	775	439
2014 through 2018	4,211	2,067
Total	$ 6,552	$ 4,129

Included in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets at December 31, 2008 and 2007 are the following amounts that have not been recognized in net periodic pension costs (in millions):

	At December 31,	
	2008	2007
Unrecognized transition obligation	$ 0.9	$ 1.0
Net of tax	0.5	0.6
Unrecognized prior service cost credit	(1.0)	(1.2)
Net of tax	(0.6)	(0.8)
Unrecognized net actuarial loss	1.3	2.8
Net of tax	0.8	1.7

Note 7. Financial Instruments

We are exposed to financial market risks, including changes in commodity prices, interest rates and foreign exchange rates. We may use financial instruments (e.g., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the types of risks we attempt to hedge are those related to (i) the variability of future earnings, (ii) fair values of certain debt obligations and (iii) cash flows resulting from changes in applicable interest rates, commodity prices or exchange rates. See Note 14 for information regarding our consolidated debt obligations.

We routinely review our outstanding financial instruments in light of current market conditions. If market conditions warrant, some financial instruments may be closed out in advance of their contractual settlement dates thus realizing income or loss depending on the specific hedging criteria. When this occurs, we may enter into a new financial instrument to reestablish the hedge to which the closed instrument relates.

The following table presents gains (losses) recorded in net income attributable to our interest rate risk and commodity risk hedging transactions for the periods indicated. These amounts do not present the corresponding gains (losses) attributable to the underlying hedged items.

	For the Year Ended December 31,		
	2008	2007	2006
Interest Rate Risk Hedging Portfolio:			
EPO:			
Reclassification of cash flow hedge amounts from AOCI, net	$ 4,409	$ 5,429	$ 4,234
Other gains (losses) from derivative transactions	5,340	(8,934)	(5,195)
Duncan Energy Partners:			
Ineffective portion of cash flow hedges	(5)	(155)	--
Reclassification of cash flow hedge amounts from AOCI, net	(2,008)	350	--
Total hedging gains (losses), net, in consolidated interest expense	$ 7,736	$ (3,310)	$ (961)
Commodity Risk Hedging Portfolio:			
EPO:			
Reclassification of cash flow hedge amounts from AOCI, net - natural gas marketing activities	$ (30,175)	$ (3,299)	$ (1,327)
Reclassification of cash flow hedge amounts from AOCI, net - NGL and petrochemical operations	(28,232)	(4,564)	13,891
Other gains (losses) from derivative transactions	29,772	(20,712)	(2,307)
Total hedging gains (losses), net, in consolidated operating costs and expenses	$ (28,635)	$ (28,575)	$ 10,257

The following table provides additional information regarding derivative instruments as presented in our Consolidated Balance Sheets at the dates indicated:

	At December 31, 2008	At December 31, 2007
Current assets:		
Derivative assets:		
Interest rate risk hedging portfolio	$ 7,780	$ --
Commodity risk hedging portfolio	185,762	341
Foreign currency risk hedging portfolio	9,284	1,308
Total derivative assets – current	$ 202,826	$ 1,649
Other assets:		
Interest rate risk hedging portfolio	$ 38,939	$ 14,744
Total derivative assets – long-term	$ 38,939	$ 14,744
Current liabilities:		
Derivative liabilities:		
Interest rate risk hedging portfolio	$ 5,910	$ 22,209
Commodity risk hedging portfolio	281,142	19,575
Foreign currency risk hedging portfolio	109	27
Total derivative liabilities – current	$ 287,161	$ 41,811
Other liabilities:		
Interest rate risk hedging portfolio	3,889	3,080
Commodity risk hedging portfolio	233	--
Total derivative liabilities– long-term	$ 4,122	$ 3,080

The following table presents gains (losses) recorded in other comprehensive income (loss) for cash flow hedges associated with our interest rate risk, commodity risk and foreign currency risk hedging portfolios. These amounts do not present the corresponding gains (losses) attributable to the underlying hedged items.

	For the Year Ended December 31, 2008	2007	2006
Interest Rate Risk Hedging Portfolio:			
EPO:			
Gains (losses) on cash flow hedges	$ (20,772)	$ 17,996	$ 11,196
Reclassification of cash flow hedge amounts to net income, net	(4,409)	(5,429)	(4,234)
Duncan Energy Partners:			
Losses on cash flow hedges	(7,989)	(3,271)	--
Reclassification of cash flow hedge amounts to net income, net	2,008	(350)	--
Total interest rate risk hedging gains (losses), net	(31,162)	8,946	6,962
Commodity Risk Hedging Portfolio:			
EPO:			
Natural gas marketing activities:			
Losses on cash flow hedges	(30,642)	(3,125)	(1,034)
Reclassification of cash flow hedge amounts to net income, net	30,175	3,299	1,327
NGL and petrochemical operations:			
Gains (losses) on cash flow hedges	(120,223)	(22,735)	9,976
Reclassification of cash flow hedge amounts to net income, net	28,232	4,564	(13,891)
Total commodity risk hedging gains (losses), net	(92,458)	(17,997)	(3,622)
Foreign Currency Risk Hedging Portfolio:			
Gains on cash flow hedges	9,286	1,308	--
Total foreign currency risk hedging gains (losses), net	9,286	1,308	--
Total cash flow hedge amounts in other comprehensive income	$ (114,334)	$ (7,743)	$ 3,340

The following information summarizes the principal elements of our interest rate risk, commodity risk and foreign currency risk hedging portfolios. For amounts recorded in net income and other comprehensive income and on our balance sheet related to our consolidated hedging activities, please refer to the preceding tables.

Interest Rate Risk Hedging Portfolio

Our interest rate exposure results from variable and fixed rate borrowings under various debt agreements. The following information summarizes significant components of our interest rate risk hedging portfolio:

Fair value hedges – EPO interest rate swaps

We manage a portion of our interest rate exposure by utilizing interest rate swaps and similar arrangements, which allow us to convert a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt. At December 31, 2008, we had four interest rate swap agreements outstanding having an aggregate notional value of $400.0 million that were accounted for as fair value hedges. The aggregate fair value of these interest rate swaps at December 31, 2008, was $46.7 million (an asset), with an offsetting increase in the fair value of the underlying debt. There were eleven interest rate swaps outstanding at December 31, 2007 having an aggregate fair value of $12.9 million (an asset).

The following table summarizes our interest rate swaps outstanding at December 31, 2008.

Hedged Fixed Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Fixed to Variable Rate (1)	Notional Value
Senior Notes C, 6.375% fixed rate, due Feb. 2013	1	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 5.015%	$100.0 million
Senior Notes G, 5.60% fixed rate, due Oct. 2014	3	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.60% to 5.297%	$300.0 million

(1) The variable rate indicated is the all-in variable rate for the current settlement period.

We have designated these interest rate swaps as fair value hedges under SFAS 133 since they mitigate changes in the fair value of the underlying fixed rate debt. As effective fair value hedges, an increase in the fair value of these interest rate swaps is equally offset by an increase in the fair value of the underlying hedged debt. The offsetting changes in fair value have no effect on current period interest expense.

Cash flow hedges – EPO treasury locks

We may enter into treasury rate lock transactions ("treasury locks") to hedge U.S. treasury rates related to its anticipated issuances of debt. Each of our treasury lock transactions was designated as a cash flow hedge. Gains or losses on the termination of such instruments are reclassified into net income (as a component of interest expense) using the effective interest method over the estimated term of the underlying fixed-rate debt. At December 31, 2008, we had no treasury lock financial instruments outstanding. At December 31, 2007, the aggregate notional value of our treasury lock financial instruments was $600.0 million, which had a total fair value (a liability) of $19.6 million. We terminated a number of treasury lock financial instruments during 2008 and 2007. These terminations resulted in realized losses of $40.4 million in 2008 and gains of $48.8 million in 2007.

We expect to reclassify $1.6 million of cumulative net gains from our interest rate risk cash flow hedges into net income (as a decrease to interest expense) during 2009.

Cash flow hedges – Duncan Energy Partners' interest rate swaps

At December 31, 2008, Duncan Energy Partners had interest rate swap agreements outstanding having an aggregate notional value of $175.0 million. These swaps were accounted for as cash flow hedges. The purpose of these financial instruments is to reduce the sensitivity of Duncan Energy Partners' earnings to the variable interest rates charged under its revolving credit facility. The aggregate fair value of these interest rate swaps at December 31, 2008 and 2007 was a liability of $9.8 million and $3.8 million, respectively. Duncan Energy Partners expects to reclassify $6.0 million of cumulative net losses from its interest rate risk cash flow hedges into net income (as an increase to interest expense) during 2009.

The following table summarizes Duncan Energy Partners' interest rate swaps outstanding at December 31, 2008.

Hedged Variable Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Variable to Fixed Rate (1)	Notional Value
DEP I Revolving Credit Facility, due Feb. 2011	3	Sep. 2007 to Sep. 2010	Sep. 2010	1.47% to 4.62%	$175.0 million

(1) Amounts receivable from or payable to the swap counterparties are settled every three months (the "settlement period").

As cash flow hedges, any increase or decrease in fair value (to the extent effective) would be recorded in other comprehensive income (loss) and amortized into earnings based on the settlement period hedged. Any ineffectiveness is recorded directly into earnings as an increase in interest expense.

Commodity Risk Hedging Portfolio

Our commodity risk hedging portfolio was impacted by a significant decline in natural gas prices during the second half of 2008. As a result of the global recession, commodity prices have continued to be volatile during the first quarter of 2009. We may experience additional losses related to our commodity risk hedging portfolio in 2009.

The prices of natural gas, NGLs and certain petrochemical products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the price risks associated with such products, we may enter into commodity financial instruments.

The primary purpose of our commodity risk management activities is to reduce our exposure to price risks associated with (i) natural gas purchases, (ii) the value of NGL production and inventories, (iii) related firm commitments, (iv) fluctuations in transportation revenues where the underlying fees are based on natural gas index prices and (v) certain anticipated transactions involving either natural gas, NGLs or certain petrochemical products. From time to time, we inject natural gas into storage and may utilize hedging instruments to lock in the value of its inventory positions. The commodity financial instruments we utilize are settled in cash.

We have segregated our commodity financial instruments portfolio between those financial instruments utilized in connection with our natural gas marketing activities and those used in connection with its NGL and petrochemical operations.

A significant number of the financial instruments in this portfolio hedge the purchase of physical natural gas. If natural gas prices fall below the price stipulated in such financial instruments, we recognize a liability for the difference; however, if prices partially or fully recover, this liability would be reduced or eliminated, as appropriate. Our restricted cash balance at December 31, 2008 was $203.8 million in order to meet commodity exchange deposit requirements and the negative change in the fair value of our natural gas hedge positions.

Natural gas marketing activities

At December 31, 2008 and 2007, the aggregate fair value of those financial instruments utilized in connection with our natural gas marketing activities was an asset of $6.5 million and a liability of $0.3 million, respectively. Almost all of the financial instruments within this portion of the commodity financial instruments portfolio are accounted for using mark-to-market accounting, with a small number accounted for as cash flow hedges. We did not have any cash flow hedges related to our natural gas marketing activities at December 31, 2008.

NGL and petrochemical operations

At December 31, 2008 and 2007, the aggregate fair value of those financial instruments utilized in connection with our NGL and petrochemical operations were liabilities of $102.1 million and $19.0 million, respectively. Almost all of the financial instruments within this portion of the commodity financial instruments portfolio are accounted for as cash flow hedges, with a small number accounted for using mark-to-market accounting. We expect to reclassify $114.0 million of cumulative net losses from these cash flow hedges into net income (as an increase in operating costs and expenses) during 2009.

We have employed a program to economically hedge a portion of our earnings from natural gas processing in the Rocky Mountain region. This program consists of (i) the forward sale of a portion of our expected equity NGL production volumes at fixed prices through 2009 and (ii) the purchase, using commodity financial instruments, of the amount of natural gas expected to be consumed as plant thermal reduction ("PTR") in the production of such equity NGL volumes. The objective of this strategy is to hedge a level of gross margins (i.e., NGL sales revenues less actual costs for PTR and the gain or loss on the PTR hedge) associated with the forward sales contracts by fixing the cost of natural gas used for PTR, through the use of commodity financial instruments. At December 31, 2008, this hedging program had hedged future expected gross margins (before plant operating expenses) of $483.9 million on 22.5 million barrels of forecasted NGL forward sales transactions extending through 2009.

Our NGL forward sales contracts are not accounted for as financial instruments under SFAS 133 since they meet normal purchase and sale exception criteria; therefore, changes in the aggregate economic value of these sales contracts are not reflected in net income and other comprehensive income until the volumes are delivered to customers. On the other hand, the commodity financial instruments used to purchase the related quantities of PTR (i.e., "PTR hedges") are accounted for as cash flow hedges; therefore, changes in the aggregate fair value of the PTR hedges are presented in other comprehensive income. Once the forecasted NGL forward sales transactions occur, any realized gains and losses on the cash flow hedges would be reclassified into net income in that period.

Prior to actual settlement, if the market price of natural gas is less than the price stipulated in a commodity financial instrument, we recognize an unrealized loss in other comprehensive loss for the excess of the natural gas price stated in the hedge over the market price. To the extent that we realize such financial losses upon settlement of the instrument, the losses are added to the actual cost we pay for PTR, which would then be based on the lower market price. Conversely, if the market price of natural gas is greater than the price stipulated in such hedges, we recognize an unrealized gain in other comprehensive income for the excess of the market price over the natural gas price stated in the PTR hedge. If realized, the gains on the financial instrument would serve to reduce the actual cost paid for PTR, which would then be based on the higher market price. The net effect of these hedging relationships is that our total cost of natural gas used for PTR approximates the amount it originally hedged under this program.

Foreign Currency Hedging Portfolio

We are exposed to foreign currency exchange rate risk primarily through a Canadian NGL marketing subsidiary. As a result, we could be adversely affected by fluctuations in the foreign currency exchange rate between the U.S. dollar and the Canadian dollar. We attempt to hedge this risk using foreign exchange purchase contracts to fix the exchange rate. Mark-to-market accounting is utilized for these contracts, which typically have a duration of one month. For the year ended December 31, 2008, we recorded minimal gains from these financial instruments.

In addition, we are exposed to foreign currency exchange rate risk through our Japanese Yen Term Loan Agreement ("Yen Term Loan") that EPO entered into in November 2008. As a result, we could be adversely affected by fluctuations in the foreign currency exchange rate between the U.S. dollar and the Japanese yen. We hedged this risk by entering into a foreign exchange purchase contract to fix the exchange rate. This purchase contract was designated as a cash flow hedge. At December 31, 2008, the fair value of this contract was $9.3 million. This contract will be settled in March 2009 upon repayment of the Yen Term Loan. Total interest expense under this loan agreement was $4.0 million, of which $1.7 million is the expected foreign currency loss, which will be recorded as interest expense.

Adoption of SFAS 157 - Fair Value Measurements

On January 1, 2008, we adopted the provisions of SFAS 157 that apply to financial assets and liabilities. We adopted the provisions of SFAS 157 that apply to nonfinancial assets and liabilities on January 1, 2009. SFAS 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date.

Our fair value estimates are based on either (i) actual market data or (ii) assumptions that other market participants would use in pricing an asset or liability. These assumptions include estimates of risk. Recognized valuation techniques employ inputs such as product prices, operating costs, discount factors and business growth rates. These inputs may be either readily observable, corroborated by market data or generally unobservable. In developing our estimates of fair value, we endeavor to utilize the best information available and apply market-based data to the extent possible. Accordingly, we utilize valuation techniques (such as the market approach) that maximize the use of observable inputs and minimize the use of unobservable inputs.

SFAS 157 established a three-tier hierarchy that classifies fair value amounts recognized or disclosed in the financial statements based on the observability of inputs used to estimate such fair values. The hierarchy considers fair value amounts based on observable inputs (Levels 1 and 2) to be more reliable and predictable than those based primarily on unobservable inputs (Level 3). At each balance sheet reporting date, we categorize our financial assets and liabilities using this hierarchy. The characteristics of fair value amounts classified within each level of the SFAS 157 hierarchy are described as follows:

- Level 1 fair values are based on quoted prices, which are available in active markets for identical assets or liabilities as of the measurement date. Active markets are defined as those in which transactions for identical assets or liabilities occur in sufficient frequency so as to provide pricing information on an ongoing basis (e.g., the NYSE or NYMEX). Level 1 primarily consists of financial assets and liabilities such as exchange-traded financial instruments, publicly-traded equity securities and U.S. government treasury securities.

- Level 2 fair values are based on pricing inputs other than quoted prices in active markets (as reflected in Level 1 fair values) and are either directly or indirectly observable as of the measurement date. Level 2 fair values include instruments that are valued using financial models or other appropriate valuation methodologies. Such financial models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value of money, volatility factors for stocks and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are (i) observable in the marketplace throughout the full term of the instrument, (ii) can be derived from observable data or (iii) are validated by inputs other than quoted prices (e.g., interest rate and yield curves at commonly quoted intervals). Level 2 includes non-exchange-traded instruments such as over-the-counter forward contracts, options and repurchase agreements.

- Level 3 fair values are based on unobservable inputs. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Unobservable inputs reflect the reporting entity's own ideas about the assumptions that market participants would use in pricing an asset or liability (including assumptions about risk). Unobservable inputs are based on the best information available in the circumstances, which might include the reporting entity's internally-developed data. The reporting entity must not ignore information about market participant assumptions that is reasonably available without undue cost and effort. Level 3 inputs are typically used in connection with internally developed valuation methodologies where management makes its best estimate of an instrument's fair value. Level 3 generally includes specialized or unique financial instruments that are tailored to meet a customer's specific needs. At December 31, 2008 our Level 3 financial assets consisted of ethane based contracts with a range of two to twelve months in term. This classification is primarily due to our reliance on broker quotes for this product due to the forward ethane markets being less than highly active.

The following table sets forth, by level within the fair value hierarchy, our financial assets and liabilities measured on a recurring basis at December 31, 2008. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Level 1	Level 2	Level 3	Total
Financial assets:				
Commodity financial instruments	$ 4,030	$ 149,180	$ 32,552	$ 185,762
Foreign currency hedging financial instruments	--	9,284	--	9,284
Interest rate financial instruments	--	46,719	--	46,719
Total	$ 4,030	$ 205,183	$ 32,552	$ 241,765
Financial liabilities:				
Commodity financial instruments	$ 7,137	$ 274,238	$ --	$ 281,375
Foreign currency hedging financial instruments	--	109	--	109
Interest rate financial instruments	--	9,799	--	9,799
Total	$ 7,137	$ 284,146	$ --	$ 291,283

Fair values associated with our interest rate, commodity and foreign currency financial instrument portfolios were developed using available market information and appropriate valuation techniques in accordance with SFAS 157.

The following table sets forth a reconciliation of changes in the fair value of our Level 3 financial assets and liabilities during the year ended December 31, 2008:

Balance, January 1, 2008	$ (4,660)
Total gains (losses) included in:	
Net income (1)	(34,807)
Other comprehensive loss	37,212
Purchases, issuances, settlements	34,807
Balance, December 31, 2008	$ 32,552

(1) There were no unrealized gains included in this amounts.

Fair Value Information

Cash and cash equivalents, accounts receivable, accounts payable and accrued expenses are carried at amounts which reasonably approximate their fair values due to their short-term nature. The estimated fair values of our fixed rate debt are based on quoted market prices for such debt or debt of similar terms and maturities. The carrying amounts of our variable rate debt obligations reasonably approximate their fair values due to their variable interest rates. The fair values associated with our interest rate and commodity hedging portfolios were developed using available market information and appropriate valuation techniques. The following table presents the estimated fair values of our financial instruments at the dates indicated:

	At December 31, 2008		At December 31, 2007	
Financial Instruments	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Financial assets:				
Cash and cash equivalents, including restricted cash	$ 239,162	$ 239,162	$ 92,866	$ 92,866
Accounts receivable	1,247,144	1,247,144	2,010,544	2,010,544
Commodity financial instruments (1)	185,762	185,762	341	341
Foreign currency hedging financial instruments (2)	9,284	9,284	1,308	1,308
Interest rate hedging financial instruments (3)	46,719	46,719	14,744	14,744
Financial liabilities:				
Accounts payable and accrued expenses	1,683,105	1,683,105	2,755,647	2,755,647
Fixed-rate debt (principal amount) (4)	7,704,296	6,638,954	5,904,000	5,867,899
Variable-rate debt	1,341,750	1,341,750	992,500	992,500
Commodity financial instruments (1)	281,375	281,375	19,575	19,575
Foreign currency hedging financial instruments (2)	109	109	27	27
Interest rate hedging financial instruments (3)	9,799	9,799	25,289	25,289

(1) Represent commodity financial instrument transactions that either have not settled or have settled and not been invoiced. Settled and invoiced transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.
(2) Relates to the hedging of our exposure to fluctuations in the Canadian dollar and Japanese yen.
(3) Represent interest rate hedging financial instrument transactions that have not settled. Settled transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.
(4) Due to the distress in the capital markets following the collapse of several major financial entities and uncertainty in the credit markets during 2008, corporate debt securities were trading at significant discounts.

Note 8. Cumulative Effect of Change in Accounting Principle

SFAS 123(R) requires us to recognize compensation expense related to equity awards based on the fair value of the award at grant date. The fair value of restricted unit awards is based on the market price of the underlying common units on the date of grant. The fair value of other equity awards is estimated using the Black-Scholes option pricing model. Under SFAS 123(R), the fair value of an equity award is amortized to earnings on a straight-line basis over the requisite service or vesting period for equity awards. Compensation for liability-classified awards is recognized over the requisite service or vesting period of an award based on the fair value of the award remeasured at each reporting period. Liability awards will be cash settled upon vesting.

Upon adoption of SFAS 123(R), we recognized, as a benefit, the cumulative effect of a change in accounting principle of $1.5 million based on the SFAS 123(R) requirement to recognize compensation expense based upon the grant date fair value of equity awards and the application of an estimated forfeiture rate to unvested awards. See Note 5 for additional information regarding our accounting for equity awards.

The following table shows unaudited pro forma net income for the year ended December 31, 2006, assuming the accounting change noted above was applied retroactively to January 1, 2006.

Pro Forma income statement amounts:		
Historical net income	$	601,155
Adjustments to derive pro forma net income:		
Effect of implementation of SFAS 123(R):		
Remove cumulative effect of change in accounting principle recorded in January 2006		(1,472)
Pro forma net income		599,683
EPGP interest		(96,969)
Pro forma net income available to limited partners	$	502,714
Pro forma per unit data (basic):		
Historical units outstanding		414,442
Per unit data:		
As reported	$	1.22
Pro forma	$	1.21
Pro forma per unit data (diluted):		
Historical units outstanding		414,759
Per unit data:		
As reported	$	1.22
Pro forma	$	1.21

Note 9. Inventories

Our inventory amounts were as follows at the dates indicated:

	At December 31,			
	2008		2007	
Working inventory (1)	$	200,439	$	342,589
Forward sales inventory (2)		162,376		11,693
Total inventory	$	362,815	$	354,282

(1) Working inventory is comprised of inventories of natural gas, NGLs and certain petrochemical products that are either available-for-sale or used in the provision for services.
(2) Forward sales inventory consists of identified NGL and natural gas volumes dedicated to the fulfillment of forward sales contracts.

Our inventory values reflect payments for product purchases, freight charges associated with such purchase volumes, terminal and storage fees, vessel inspection costs, demurrage charges and other related costs. We value our inventories at the lower of average cost or market.

Operating costs and expenses, as presented on our Statements of Consolidated Operations, include cost of sales amounts related to the sale of inventories. Our costs of sales were $18.66 billion, $14.51 billion and $11.78 billion for the years ended December 31, 2008, 2007 and 2006, respectively.

In those instances where we take ownership of inventory volumes through percent-of-liquids contracts and similar arrangements (as opposed to actually purchasing volumes for cash from third parties, see Note 4), these volumes are valued at market-related prices during the month in which they are acquired. We capitalize as a component of inventory those ancillary costs (e.g. freight-in and other handling and processing charges) incurred in connection with volumes obtained through such contracts.

Due to fluctuating commodity prices in the NGL, natural gas and petrochemical industry, we recognize lower of cost or market ("LCM") adjustments when the carrying value of our inventories exceed their net realizable value. These non-cash charges are a component of cost of sales in the period they are recognized and generally affect our segment operating results in the following manner:

- Write-downs of NGL inventories are recorded as a cost of our NGL marketing activities within our NGL Pipelines & Services business segment;
- Write-downs of natural gas inventories are recorded as a cost of our natural gas pipeline operations within our Onshore Natural Gas Pipelines & Services business segment; and
- Write-downs of petrochemical inventories are recorded as a cost of our petrochemical marketing activities or octane additive production business within our Petrochemical Services business segment, as applicable.

For the years ended December 31, 2008, 2007 and 2006, we recognized LCM adjustments of approximately $50.7 million, $13.3 million and $18.6 million, respectively. To the extent our commodity hedging strategies address inventory-related risks and are successful, these inventory valuation adjustments are mitigated or offset. See Note 7 for a description of our commodity hedging activities.

Note 10. Property, Plant and Equipment

Our property, plant and equipment values and accumulated depreciation balances were as follows at the dates indicated:

	Estimated Useful Life in Years	At December 31, 2008	At December 31, 2007
Plants and pipelines (1)	3-40 (5)	$ 12,296,318	$ 10,884,819
Underground and other storage facilities (2)	5-35 (6)	900,664	720,795
Platforms and facilities (3)	20-31	634,761	637,812
Transportation equipment (4)	3-10	38,771	32,627
Land		54,627	48,172
Construction in progress		1,604,691	1,173,988
Total		15,529,832	13,498,213
Less accumulated depreciation		2,375,058	1,910,949
Property, plant and equipment, net		$ 13,154,774	$ 11,587,264

(1) Plants and pipelines include processing plants; NGL, petrochemical, oil and natural gas pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings; laboratory and shop equipment; and related assets.
(2) Underground and other storage facilities include underground product storage caverns; storage tanks; water wells; and related assets.
(3) Platforms and facilities include offshore platforms and related facilities and other associated assets.
(4) Transportation equipment includes vehicles and similar assets used in our operations.
(5) In general, the estimated useful lives of major components of this category are as follows: processing plants, 20-35 years; pipelines, 18-40 years (with some equipment at 5 years); terminal facilities, 10-35 years; office furniture and equipment, 3-20 years; buildings, 20-35 years; and laboratory and shop equipment, 5-35 years.
(6) In general, the estimated useful lives of major components of this category are as follows: underground storage facilities, 20-35 years (with some components at 5 years); storage tanks, 10-35 years; and water wells, 25-35 years (with some components at 5 years).

The following table summarizes our depreciation expense and capitalized interest amounts for the periods indicated:

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Depreciation expense (1)	$ 466,054	$ 414,901	$ 350,832
Capitalized interest (2)	$ 71,584	$ 75,476	$ 55,660

(1) Depreciation expense is a component of costs and expenses as presented in our Statements of Consolidated Operations.

(2) Capitalized interest increases the carrying value of the associated asset and reduces interest expense during the period it is recorded.

We reviewed assumptions underlying the estimated remaining useful lives of certain of our assets during the first quarter of 2008. As a result of our review, effective January 1, 2008, we revised the remaining useful lives of these assets, most notably the assets that constitute our Texas Intrastate System. This revision increased the remaining useful life of such assets to incorporate recent data showing that proved natural gas reserves supporting throughput and processing volumes for these assets have changed since our original determination made in September 2004. These revisions will prospectively reduce our depreciation expense on assets having carrying values totaling $2.72 billion as of January 1, 2008. On average, we extended the life of these assets by 3.1 years. As a result of this change in estimate, depreciation expense included in operating income and net income for the year ended December 31, 2008 decreased by approximately $20.0 million, which increased our basic and diluted earnings per unit by $0.04 from what it would have been absent the change.

Asset retirement obligations

We have recorded AROs related to legal requirements to perform retirement activities as specified in contractual arrangements and/or governmental regulations. In general, our AROs primarily result from (i) right-of-way agreements associated with our pipeline operations, (ii) leases of plant sites and (iii) regulatory requirements triggered by the abandonment or retirement of certain underground storage assets and offshore facilities. In addition, our AROs may result from the renovation or demolition of certain assets containing hazardous substances such as asbestos.

The following table presents information regarding our AROs since December 31, 2006.

ARO liability balance, December 31, 2006	$ 24,403
Liabilities incurred	1,673
Liabilities settled	(5,069)
Revisions in estimated cash flows	15,645
Accretion expense	3,962
ARO liability balance, December 31, 2007	$ 40,614
Liabilities incurred	1,064
Liabilities settled	(7,229)
Revisions in estimated cash flows	1,163
Accretion expense	2,114
ARO liability balance, December 31, 2008	$ 37,726

Property, plant and equipment at December 31, 2008 and 2007 includes $9.9 million and $10.6 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset. We estimate that accretion expense will approximate $2.1 million for 2009, $2.2 million for 2010, $2.4 million for 2011, $2.6 million for 2012 and $2.9 million for 2013.

Certain of our unconsolidated affiliates have AROs recorded at December 31, 2008 and 2007 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our financial statements.

Note 11. Investments in and Advances to Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for using the equity method of accounting. Our investments in and advances to unconsolidated affiliates are grouped according to the business segment to which they relate. See Note 16 for a general discussion of our business segments. The following table shows our investments in and advances to unconsolidated affiliates at the dates indicated.

	Ownership Percentage at December 31, 2008	December 31, 2008	December 31, 2007
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C. ("VESCO")	13.1%	$ 37,673	$ 40,129
K/D/S Promix, L.L.C. ("Promix")	50.0%	46,380	51,537
Baton Rouge Fractionators LLC ("BRF")	32.2%	24,160	25,423
Skelly-Belvieu Pipeline Company, L.L.C. ("Skelly-Belvieu") (1)	49.0%	35,969	--
Onshore Natural Gas Pipelines & Services:			
Jonah Gas Gathering Company ("Jonah")	19.4%	258,066	235,837
Evangeline (2)	49.5%	4,528	3,490
White River Hub, LLC ("White River Hub") (3)	50.0%	21,387	--
Offshore Pipelines & Services:			
Poseidon Oil Pipeline, L.L.C. ("Poseidon")	36.0%	60,233	58,423
Cameron Highway Oil Pipeline Company ("Cameron Highway") (4)	50.0%	250,833	256,588
Deepwater Gateway, L.L.C. ("Deepwater Gateway")	50.0%	104,784	111,221
Neptune	25.7%	52,671	55,468
Nemo (5)	33.9%	432	2,888
Texas Offshore Port System	33.3%	35,890	--
Petrochemical Services:			
Baton Rouge Propylene Concentrator, LLC ("BRPC")	30.0%	12,633	13,282
La Porte (6)	50.0%	3,887	4,053
Total		$ 949,526	$ 858,339

(1) In December 2008, we acquired a 49.0% ownership interest in Skelly-Belvieu.
(2) Refers to our ownership interests in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively.
(3) In February 2008, we acquired a 50.0% ownership interest in White River Hub.
(4) During the year ended December 31, 2007, we contributed $216.5 million to Cameron Highway to fund our portion of the repayment of Cameron Highway's debt.
(5) The December 31, 2007 amount includes a $7.0 million non-cash impairment charge attributable to our investment in Nemo.
(6) Refers to our ownership interests in La Porte Pipeline Company, L.P. and La Porte GP, LLC, collectively.

On occasion, the price we pay to acquire an ownership interest in a company exceeds the underlying book value of the capital accounts we acquire. Such excess cost amounts are included within the carrying values of our investments in and advances to unconsolidated affiliates. At December 31, 2008 and 2007, our investments in Promix, La Porte, Neptune, Poseidon, Cameron Highway and Jonah included excess cost amounts totaling $43.7 million and $43.8 million, respectively, all of which were attributable to the fair value of the underlying tangible assets of these entities exceeding their book carrying values at the time of our acquisition of interests in these entities. To the extent that we attribute all or a portion of an excess cost amount to higher fair values, we amortize such excess cost as a reduction in equity earnings in a manner similar to depreciation. To the extent we attribute an excess cost amount to goodwill, we do not amortize this amount but it is subject to evaluation for impairment. Amortization of such excess cost amounts was $2.1 million, $2.6 million and $2.1 million for the years ended December 31, 2008, 2007 and 2006, respectively.

The following table presents our equity in earnings of unconsolidated affiliates for the periods indicated:

	For the Year Ended December 31,		
	2008	2007	2006
NGL Pipelines & Services:			
VESCO	$ (1,519)	$ 3,507	$ 1,719
Promix	1,977	514	1,353
BRF	1,003	2,010	2,643
Skelly-Belvieu	(31)	--	--
Onshore Natural Gas Pipelines & Services:			
Evangeline	896	183	958
Coyote Gas Treating, LLC ("Coyote")	--	--	1,676
Jonah	21,408	9,357	238
White River Hub	655	--	--
Offshore Pipelines & Services:			
Poseidon	6,883	10,020	11,310
Cameron Highway	16,358	(11,200)	(11,000)
Deepwater Gateway	17,062	20,606	18,392
Neptune (1)	(5,683)	(821)	(8,294)
Nemo (2)	(973)	(5,977)	1,501
Texas Offshore Port System	(38)	--	--
Petrochemical Services:			
BRPC	1,877	2,266	1,864
La Porte	(771)	(807)	(795)
Total	$ 59,104	$ 29,658	$ 21,565

(1) Equity in earnings from Neptune for 2006 include a $7.4 million non-cash impairment charge.
(2) Equity in earnings from Nemo for 2007 include a $7.0 million non-cash impairment charge.

NGL Pipelines & Services

At December 31, 2008, our NGL Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

VESCO. We own a 13.1% interest in VESCO, which owns a natural gas processing facility and related assets located in south Louisiana.

Promix. We own a 50.0% interest in Promix, which owns an NGL fractionation facility and related storage and pipeline assets located in south Louisiana.

BRF. We own an approximate 32.2% interest in BRF, which owns an NGL fractionation facility located in south Louisiana.

Skelly-Belvieu. In December 2008, we acquired a 49.0% interest in Skelly-Belvieu for $36.0 million. Skelly-Belvieu owns a 570-mile pipeline that transports mixed NGLs to markets in southeast Texas.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's current unconsolidated affiliates are summarized below.

	At December 31,	
	2008	**2007**
BALANCE SHEET DATA:		
Current assets	$ 64,080	$ 112,352
Property, plant and equipment, net	368,059	270,586
Other assets	2,011	11,686
Total assets	$ 434,150	$ 394,624
Current liabilities	$ 50,180	$ 75,314
Other liabilities	24,271	9,095
Combined equity	359,699	310,215
Total liabilities and combined equity	$ 434,150	$ 394,624

	For the Year Ended December 31,		
	2008	**2007**	**2006**
INCOME STATEMENT DATA:			
Revenues	$ 271,263	$ 220,381	$ 190,320
Operating income (loss)	20,518	41,147	(26,885)
Net income (loss)	20,872	26,506	(25,543)

Onshore Natural Gas Pipelines & Services

At December 31, 2008, our Onshore Natural Gas Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

Evangeline. We own an approximate 49.5% aggregate interest in Evangeline, which owns a natural gas pipeline located in south Louisiana. A subsidiary of Acadian Gas, LLC owns the Evangeline interests, which were contributed to Duncan Energy Partners in February 2007 in connection with its initial public offering (see Note 17).

Coyote. We owned a 50.0% interest in Coyote during 2005, which owns a natural gas treating facility located in the San Juan Basin of southwestern Colorado. During 2006, we sold our interest in Coyote and recorded a gain on the sale of $3.3 million.

Jonah. Our equity interest in Jonah at December 31, 2008 is based on capital contributions we made to Jonah in connection with its Phase V expansion project. We completed Phase I of this expansion in July 2007 entitling us to approximately 19.4% in earnings and ownership with the remaining 80.6% entitlement to TEPPCO. See Note 17 for additional information regarding our Jonah affiliate. Jonah owns the Jonah Gas Gathering System located in the Greater Green River Basin of southwestern Wyoming.

White River Hub. We own a 50.0% interest in White River Hub, which owns a natural gas hub located in northwest Colorado. The hub was completed in December 2008.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's current unconsolidated affiliates are summarized below.

	At December 31, 2008	At December 31, 2007
BALANCE SHEET DATA:		
Current assets	$ 97,470	$ 83,962
Property, plant and equipment, net	1,082,251	915,572
Other assets	158,682	176,091
Total assets	$ 1,338,403	$ 1,175,625
Current liabilities	$ 62,147	$ 43,951
Other liabilities	21,890	25,002
Combined equity	1,254,366	1,106,672
Total liabilities and combined equity	$ 1,338,403	$ 1,175,625

	For the Year Ended December 31, 2008	2007	2006
INCOME STATEMENT DATA:			
Revenues	$ 605,353	$ 477,077	$ 372,240
Operating income	118,907	98,549	48,387
Net income	114,911	93,491	40,608

Offshore Pipelines & Services

At December 31, 2008, our Offshore Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

Poseidon. We own a 36.0% interest in Poseidon, which owns a crude oil pipeline that gathers production from the outer continental shelf and deepwater areas of the Gulf of Mexico for delivery to onshore locations in south Louisiana.

Cameron Highway. We own a 50.0% interest in Cameron Highway, which owns a crude oil pipeline that gathers production from deepwater areas of the Gulf of Mexico, primarily the South Green Canyon area, for delivery to refineries and terminals in southeast Texas.

Cameron Highway repaid its $365.0 million Series A notes and $50.0 million Series B notes in 2007 using cash contributions from its partners. We funded our 50.0% share of the capital contributions using borrowings under EPO's Multi-Year Revolving Credit Facility. Cameron Highway incurred a $14.1 million make-whole premium in connection with the repayment of its Series A notes.

Deepwater Gateway. We own a 50.0% interest in Deepwater Gateway, which owns the Marco Polo platform located in the Gulf of Mexico. The Marco Polo platform processes crude oil and natural gas production from the Marco Polo, K2, K2 North and Genghis Khan fields located in the South Green Canyon area of the Gulf of Mexico.

Neptune. We own a 25.7% interest in Neptune, which owns Manta Ray Offshore Gathering System ("Manta Ray") and Nautilus Pipeline System ("Nautilus"), which are natural gas pipelines located in the Gulf of Mexico.

Nemo. We own a 33.9% interest in Nemo, which owns the Nemo Gathering System, which is a natural gas pipeline located in the Gulf of Mexico.

Texas Offshore Port System. In August 2008, we, together with TEPPCO and Oiltanking Holding Americas, Inc. ("Oiltanking"), announced the formation of the Texas Offshore Port System, a joint venture to design, construct, operate and own a Texas offshore crude oil port and a related onshore pipeline and storage system that would facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. Demand for such projects is being driven by planned and expected refinery expansions along the Gulf Coast, expected increases in shipping traffic and operating limitations of regional ship channels. We own a one-third interest in the Texas Offshore Port System. See Note 17 for additional information regarding this joint venture.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's current unconsolidated affiliates are summarized below.

	At December 31, 2008	At December 31, 2007
BALANCE SHEET DATA:		
Current assets	$ 106,392	$ 46,795
Property, plant and equipment, net	1,184,549	1,122,108
Other assets	3,608	4,338
Total assets	$ 1,294,549	$ 1,173,241
Current liabilities	$ 58,379	$ 19,720
Other liabilities	116,654	96,791
Combined equity	1,119,516	1,056,730
Total liabilities and combined equity	$ 1,294,549	$ 1,173,241

	For the Year Ended December 31, 2008	2007	2006
INCOME STATEMENT DATA:			
Revenues	$ 163,916	$ 156,780	$ 153,996
Operating income	68,969	85,550	71,977
Net income	65,554	53,590	42,732

Neptune owns Manta Ray and Nautilus. Manta Ray gathers natural gas originating from producing fields located in the Green Canyon, Southern Green Canyon, Ship Shoal, South Timbalier and Ewing Bank areas of the Gulf of Mexico to numerous downstream pipelines, including the Nautilus pipeline. Nautilus connects our Manta Ray pipeline to our Neptune natural gas processing plant located in south Louisiana. Due to a recent decrease in throughput volumes on the Manta Ray and Nautilus pipelines, we evaluated our 25.7% investment in Neptune for impairment during the third quarter of 2006. The decrease in throughput volumes is primarily due to underperformance of certain fields, natural depletion and hurricane-related delays in starting new production. These factors contributed to significant delays in throughput volumes Neptune expects to receive. As a result, Neptune has experienced operating losses in recent periods.

Our review of Neptune's estimated cash flows during the third quarter of 2006 indicated that the carrying value of our investment exceeded its fair value, which resulted in a non-cash impairment charge of $7.4 million. This loss is recorded as a component of "Equity in earnings of unconsolidated affiliates" in our Statement of Consolidated Operations for the year ended December 31, 2006.

Nemo was formed in 1999 to construct, own and operate the Nemo Gathering System, a 24-mile natural gas gathering system in the Gulf of Mexico offshore Louisiana. The Nemo Gathering System, which began operations in 2001, gathers natural gas from certain developments in the Green Canyon area of the Gulf of Mexico to a pipeline interconnect with the Manta Ray Gathering System. Due to a recent decrease in throughput volumes on the Nemo Gathering System, we evaluated our 33.9% investment in Nemo for impairment during the second quarter of 2007. The decrease in throughput volumes is primarily due to underperformance of certain fields and natural depletion.

Our review of Nemo's estimated future cash flows during the second quarter of 2007 indicated that the carrying value of our investment exceeded its fair value, which resulted in a non-cash impairment charge of $7.0 million. This loss is recorded as a component of "Equity in earnings of unconsolidated affiliates" in our Statement of Consolidated Operations for the year ended December 31, 2007. After recording this impairment charge, the carrying value of our investment in Nemo at December 31, 2007 was $2.9 million.

Our investments in Neptune and Nemo were written down to fair value, which management estimated using recognized business valuation techniques. The fair value analysis is based upon management's expectation of future cash flows, which incorporates certain industry information and assumptions made by management. For example, the individual reviews of Neptune and Nemo included management estimates regarding natural gas reserves of producers served by both Neptune and Nemo, respectively. If the assumptions underlying our fair value analysis change and expected cash flows are reduced, additional impairment charges may result.

Petrochemical Services

At December 31, 2008, our Petrochemical Services segment included the following unconsolidated affiliates accounted for using the equity method:

BRPC. We own a 30.0% interest in BRPC, which owns a propylene fractionation facility located in south Louisiana.

La Porte. We own an aggregate 50.0% interest in La Porte, which owns a propylene pipeline extending from Mont Belvieu, Texas to La Porte, Texas.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's current unconsolidated affiliates are summarized below.

	At December 31,	
	2008	2007
BALANCE SHEET DATA:		
Current assets	$ 3,634	$ 3,187
Property, plant and equipment, net	43,720	47,322
Total assets	$ 47,354	$ 50,509
Current liabilities	$ 1,737	$ 970
Other liabilities	2	2
Combined equity	45,615	49,537
Total liabilities and combined equity	$ 47,354	$ 50,509

	For the Year Ended December 31,		
	2008	2007	2006
INCOME STATEMENT DATA:			
Revenues	$ 20,990	$ 19,844	$ 19,014
Operating income	4,666	5,961	4,626
Net income	4,693	6,029	4,729

Note 12. Business Combinations

2008 Transactions

Our expenditures for business combinations during the year ended December 31, 2008 were $202.2 million and primarily reflect the acquisitions described below.

On a pro forma consolidated basis, our revenues, costs and expenses, operating income, net income and earnings per unit amounts would not have differed materially from those we actually reported for 2008, 2007 and 2006 due to the immaterial nature of our 2008 business combination transactions.

Great Divide Gathering System Acquisition. In December 2008, one of our affiliates, Enterprise Gas Processing, LLC, purchased a 100.0% membership interest in Great Divide Gathering, LLC ("Great Divide") for cash consideration of $125.2 million. Great Divide was wholly owned by EnCana Oil & Gas ("EnCana").

The assets of Great Divide consist of a 31-mile natural gas gathering system, the Great Divide Gathering System, located in the Piceance Basin of northwestern Colorado. The Great Divide Gathering System extends from the southern portion of the Piceance Basin, including production from EnCana's Mamm Creek field, to a pipeline interconnection with our Piceance Basin Gathering System. Volumes of natural gas originating on the Great Divide Gathering System are transported through our Piceance Creek Gathering System to our 1.4 Bcf/d Meeker natural gas treating and processing complex. A significant portion of these volumes are produced by EnCana, one of the largest natural gas producers in the region, and are dedicated the Great Divide and Piceance Creek Gathering Systems for the life of the associated lease holdings.

Tri-States and Belle Rose Acquisitions. In October 2008, we acquired additional 16.7% membership interests in both Tri-States NGL Pipeline, L.L.C. ("Tri-States") and Belle Rose NGL Pipeline, L.L.C. ("Belle Rose") for total cash consideration of $19.9 million. As a result of this transaction, our ownership interest in Tri-States increased to 83.3%. We now own 100.0% of the membership interests in Belle Rose.

Tri-States owns a 194-mile NGL pipeline located along the Mississippi, Alabama and Louisiana Gulf Coast. Belle Rose owns a 48-mile NGL pipeline located in Louisiana. These systems, in conjunction with the Wilprise pipeline, transport mixed NGLs to the BRF, Norco and Promix NGL fractionators located in south Louisiana.

Acquisition of Remaining Interest in Dixie. In August 2008, we acquired the remaining 25.8% ownership interests in Dixie for cash consideration of $57.1 million. As a result of this transaction, we own 100.0% of Dixie, which owns a 1,371-mile pipeline system that delivers NGLs (primarily propane and other chemical feedstock) to customers along the U.S. Gulf Coast and southeastern United States.

Purchase Price Allocations. We accounted for business combinations completed during the year ended December 31, 2008 using the purchase method of accounting and, accordingly, such costs have been allocated to assets acquired and liabilities assumed based on estimated preliminary fair values. Such preliminary values have been developed using recognized business valuation techniques and are subject to change pending a final valuation analysis.

	Great Divide	**Tri-States**	**Belle Rose**	**Dixie**	**Other** (1)	**Total**
Assets acquired in business combination:						
Current assets	$ --	$ 813	$ 143	$ 4,021	$ 35	$ 5,012
Property, plant and equipment, net	70,643	18,417	1,129	33,727	(12,773)	111,143
Intangible assets	9,760	--	--	--	12,747	22,507
Other assets	--	46	--	382	--	428
Total assets acquired	80,403	19,276	1,272	38,130	9	139,090
Liabilities assumed in business combination:						
Current liabilities	--	(581)	(68)	(2,581)	--	(3,230)
Long-term debt	--	--	--	(2,582)	--	(2,582)
Other long-term liabilities	(81)	--	(4)	(46,265)	--	(46,350)
Total liabilities assumed	(81)	(581)	(72)	(51,428)	--	(52,162)
Total assets acquired plus liabilities assumed	80,322	18,695	1,200	(13,298)	9	86,928
Total cash used for business combinations	125,175	18,695	1,200	57,089	1	202,160
Goodwill	$ 44,853	$ --	$ --	$ 70,387	$ (8)	$ 115,232

(1) Primarily represents non-cash reclassification adjustments to December 2007 preliminary fair value estimates for assets acquired in the South Monco natural gas pipeline business ("South Monco") acquisition.

As a result of our 100% ownership interest in Dixie, we used push-down accounting to record this business combination. In doing so, a temporary tax difference was created between the assets and liabilities of Dixie for financial reporting and tax purposes. Dixie recorded a deferred income tax liability of $45.1 million attributable to the temporary tax difference.

2007 Transactions

On a pro forma consolidated basis, our revenues, costs and expenses, operating income, net income and earnings per unit amounts would not have differed materially from those we actually reported for 2007 and 2006 due to immaterial nature of our 2007 business combination transactions.

Our expenditures for business combinations during the year ended December 31, 2007 were $35.8 million, which primarily reflect the $35.0 million we spent to acquire South Monco in December 2007. This business includes approximately 128 miles of natural gas pipelines located in southeast Texas. The remaining business combination related amounts for 2007 consist of purchase price adjustments to prior period transactions.

We accounted for our 2007 business combinations using the purchase method of accounting and, accordingly, such costs have been allocated to assets acquired and liabilities assumed based on estimated preliminary fair values. Such preliminary values have been developed using recognized business valuation techniques and are subject to change pending a final valuation analysis.

2006 Transactions

Our expenditures for business combinations during the year ended December 31, 2006 were $276.5 million and primarily reflect the Encinal and Piceance Creek acquisitions described below.

Encinal Acquisition. In July 2006, we acquired the Encinal and Canales natural gas gathering systems and related gathering and processing contracts that comprised the South Texas natural gas transportation and processing business of an affiliate of Lewis Energy Group, L.P. ("Lewis"). The aggregate value of total consideration we paid or issued to complete this business combination (referred to as the "Encinal acquisition") was $326.3 million, which consisted of $145.2 million in cash and 7,115,844 of our common units.

The Encinal and Canales gathering systems are located in South Texas and are connected to over 1,450 natural gas wells producing from the Olmos and Wilcox formations. The Encinal system consists of 449 miles of pipeline, which is comprised of 277 miles of pipeline we acquired from Lewis in this transaction and 172 miles of pipeline that we own and had previously leased to Lewis. The Canales gathering system is comprised of 32 miles of pipeline. Currently, natural gas volumes gathered by the Encinal and Canales systems are transported by our existing Texas Intrastate System and are processed by our South Texas natural gas processing plants.

The Encinal and Canales gathering systems will be supported by a life of reserves gathering and processing dedication by Lewis related to its natural gas production from the Olmos formation. In addition, we entered into a 10-year agreement with Lewis for the transportation of natural gas treated at its proposed Big Reef facility. This facility will treat natural gas from the southern portion of the Edwards Trend in South Texas. We also entered into a 10-year agreement with Lewis for the gathering and processing of rich gas it produces from below the Olmos formation.

The total consideration we paid or granted to Lewis in connection with the Encinal acquisition is as follows:

Cash payment to Lewis	$ 145,197
Fair value of our 7,115,844 common units issued to Lewis	181,112
Total consideration	$ 326,309

In accordance with purchase accounting, the value of our common units issued to Lewis was based on the average closing price of such units immediately prior to and after the transaction was announced on July 12, 2006. For purposes of this calculation, the average closing price was $25.45 per unit.

Since the closing date of the Encinal acquisition was July 1, 2006, our Statements of Consolidated Operations do not include any earnings from these assets prior to this date. Given the relative size of the Encinal acquisition to our other business combination transactions during 2006, the following table presents selected pro forma earnings information for the year ended December 31, 2006 as if the Encinal acquisition had been completed on January 1, 2006, instead of July 1, 2006. This information was prepared based on financial data available to us and reflects certain estimates and assumptions made by our management. Our pro forma financial information is not necessarily indicative of what our consolidated financial results would have been had the Encinal acquisition actually occurred on January 1, 2006. The amounts shown in the following table are in millions, except per unit amounts.

	For the Year Ended December 31, 2006
Pro forma earnings data:	
Revenues	$ 14,066
Costs and expenses	13,228
Operating income	859
Net income	598
Basic earnings per unit ("EPU"):	
Units outstanding, as reported	414
Units outstanding, pro forma	422
Basic EPU, as reported	$ 1.22
Basic EPU, pro forma	$ 1.19
Diluted EPU:	
Units outstanding, as reported	415
Units outstanding, pro forma	422
Diluted EPU, as reported	$ 1.22
Diluted EPU, pro forma	$ 1.19

Piceance Creek Acquisition. In December 2006, we purchased a 100.0% interest in Piceance Creek Pipeline, LLC ("Piceance Creek"), for $100.0 million. Piceance Creek was wholly owned by EnCana.

The assets of Piceance Creek consist of a recently constructed 48-mile natural gas gathering pipeline, the Piceance Creek Gathering System, located in the Piceance Basin of northwestern Colorado. The Piceance Creek Gathering System has a transportation capacity of 1.6 Bcf/d of natural gas and extends from a connection with EnCana's Great Divide Gathering System located near Parachute, Colorado, northward through the heart of the Piceance Basin to our 1.4 Bcf/d Meeker natural gas treating and processing complex. Connectivity to EnCana's Great Divide Gathering System (see above for our purchase of this system in 2008) will provide the Piceance Creek Gathering System with access to production from the southern portion of the Piceance basin, including production from EnCana's Mamm Creek field. The Piceance Creek Gathering System was placed in service in January 2007 and began transporting initial volumes of approximately 300 million cubic feet per day ("MMcf/d") of natural gas. In conjunction with our acquisition of Piceance Creek, EnCana signed a long-term, fixed fee gathering agreement with us and dedicated significant production to the Piceance Creek Gathering System for the life of the associated lease holdings.

Other Transactions. In addition to the Encinal and Piceance Creek acquisitions, our business combinations during 2006 included the purchase of (i) an additional 8.2% ownership interest in Dixie for $12.9 million, (ii) all of the capital stock of an affiliated NGL marketing company located in Canada from related parties for $17.7 million (see Note 17) and (iii) a storage business in Flagstaff, Arizona for $0.7 million.

Note 13. Intangible Assets and Goodwill

Identifiable Intangible Assets

The following table summarizes our intangible assets at the dates indicated:

	At December 31, 2008			At December 31, 2007		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services:						
Shell Processing Agreement	$ 206,216	$ (89,299)	$ 116,917	$ 206,216	$ (78,252)	$ 127,964
Encinal gas processing customer relationship	127,119	(28,045)	99,074	127,119	(17,470)	109,649
STMA and GulfTerra NGL Business customer relationships	49,784	(21,570)	28,214	49,784	(17,537)	32,247
Pioneer gas processing contracts	37,752	(3,601)	34,151	37,752	(736)	37,016
Markham NGL storage contracts	32,664	(18,509)	14,155	32,664	(14,154)	18,510
Toca-Western contracts	31,229	(10,280)	20,949	31,229	(8,718)	22,511
Other (1)	52,295	(14,745)	37,550	35,261	(10,087)	25,174
Segment total	537,059	(186,049)	351,010	520,025	(146,954)	373,071
Onshore Natural Gas Pipelines & Services:						
San Juan Gathering System customer relationships	331,311	(92,471)	238,840	331,311	(73,087)	258,224
Petal & Hattiesburg natural gas storage contracts	100,499	(36,524)	63,975	100,499	(27,931)	72,568
Other (2)	41,501	(10,854)	30,647	31,741	(8,381)	23,360
Segment total	473,311	(139,849)	333,462	463,551	(109,399)	354,152
Offshore Pipelines & Services:						
Offshore pipeline & platform customer relationships	205,845	(90,686)	115,159	205,845	(73,905)	131,940
Other	1,167	(107)	1,060	1,167	(49)	1,118
Segment total	207,012	(90,793)	116,219	207,012	(73,954)	133,058
Petrochemical Services:						
Mont Belvieu propylene fractionation contracts	53,000	(10,474)	42,526	53,000	(8,960)	44,040
Other (3)	14,906	(2,707)	12,199	14,906	(2,227)	12,679
Segment total	67,906	(13,181)	54,725	67,906	(11,187)	56,719
Total all segments	$ 1,285,288	$ (429,872)	$ 855,416	$ 1,258,494	$ (341,494)	$ 917,000

(1) In 2008, we acquired \$6.0 million of certain permits related to our Mont Belvieu complex and had \$12.7 million of purchase price allocation adjustments related to San Felipe customer relationships from the December 2007 South Monco acquisition.
(2) In 2008, we acquired \$9.8 million of customer relationships due to the Great Divide business combination.
(3) In 2007, we paid \$11.2 million for certain air emission credits related to our Morgan's Point facility.

The following table presents the amortization expense of our intangible assets by segment for the periods indicated:

	For the Year Ended December 31,		
	2008	2007	2006
NGL Pipelines & Services	$ 39,095	$ 36,419	$ 31,159
Onshore Natural Gas Pipelines & Services	30,450	31,997	33,447
Offshore Pipelines & Services	16,839	19,318	22,156
Petrochemical Services	1,994	1,993	1,993
Total all segments	$ 88,378	$ 89,727	$ 88,755

We estimate that amortization expense associated with existing intangible assets will approximate \$82.7 million in 2009, \$77.8 million in 2010, \$71.9 million in 2011, \$62.3 million in 2012 and \$56.4 million in 2013.

In general, our intangible assets fall within two categories – contract-based intangible assets and customer relationships. Contract-based intangible assets represent commercial rights we acquired in connection with business combinations or asset purchases. Customer relationship intangible assets represent customer bases that we acquired in connection with business combinations and asset purchases. The values assigned to intangible assets are amortized to earnings using either (i) a straight-line approach or (ii) other methods that closely resemble the pattern in which the economic benefits of associated resource bases are estimated to be consumed or otherwise used, as appropriate.

We acquired $141.3 million of intangible assets primarily attributable to customer relationships we acquired in connection with the Encinal acquisition. The $132.9 million of intangible assets we acquired in connection with the Encinal acquisition (see Note 12) represents the value we assigned to customer relationships, particularly the long-term relationship we now have with Lewis through natural gas processing and gathering arrangements. We recorded $127.1 million in our NGL Pipelines & Services segment associated with processing arrangements and $5.8 million in our Onshore Natural Gas Pipelines & Services segment associated with gathering arrangements. These intangible assets will be amortized to earnings over a 20-year life using methods that closely resemble the pattern in which we estimate the depletion of the underlying natural gas resources to occur.

We acquired numerous customer relationship and contract-based intangible assets in connection with the GulfTerra Merger. The customer relationship intangible assets represent the exploration and production, natural gas processing and NGL fractionation customer bases served by GulfTerra and the South Texas midstream assets at the time the merger was completed. The contract-based intangible assets represent the rights we acquired in connection with discrete contracts to provide storage services for natural gas and NGLs that GulfTerra had entered into prior to the merger.

The value we assigned to these customer relationships is being amortized to earnings using methods that closely resemble the pattern in which the economic benefits of the underlying oil and natural gas resource bases from which the customers produce are estimated to be consumed or otherwise used. Our estimate of the useful life of each resource base is based on a number of factors, including reserve estimates, the economic viability of production and exploration activities and other industry factors. This group of intangible assets primarily consists of the (i) Offshore Pipelines & Platforms customer relationships; (ii) San Juan Gathering System customer relationships; (iii) Texas Intrastate pipeline customer relationships; and (iv) STMA and GulfTerra NGL Business customer relationships.

The contract-based intangible assets we acquired in connection with the GulfTerra Merger are being amortized over the estimated useful life (or term) of each agreement, which we estimate to range from two to eighteen years. This group of intangible assets consists of the (i) Petal and Hattiesburg natural gas storage contracts and (ii) Markham NGL storage contracts.

The Shell Processing Agreement grants us the right to process Shell's (or its assignee's) current and future production within the state and federal waters of the Gulf of Mexico. We acquired this intangible asset in connection with our 1999 purchase of certain of Shell's midstream energy assets located along the Gulf Coast. The value of the Shell Processing Agreement is being amortized on a straight-line basis over the remainder of its initial 20-year contract term through 2019.

Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. Goodwill is not amortized; however, it is subject to annual impairment testing. The following table summarizes our goodwill amounts by segment at the dates indicated:

	At December 31, 2008	At December 31, 2007
NGL Pipelines & Services		
GulfTerra Merger	$ 23,854	$ 23,854
Acquisition of Indian Springs natural gas processing business	13,162	13,162
Acquisition of Encinal	95,272	95,280
Acquisition of interest in Dixie	80,279	9,892
Acquisition of Great Divide	44,853	--
Other	11,518	11,518
Onshore Natural Gas Pipelines & Services		
GulfTerra Merger	279,956	279,956
Acquisition of Indian Springs natural gas gathering business	2,165	2,165
Offshore Pipelines & Services		
GulfTerra Merger	82,135	82,135
Petrochemical Services		
Acquisition of Mont Belvieu propylene fractionation business	73,690	73,690
Total	$ 706,884	$ 591,652

In 2008, our only significant changes to goodwill were the recording of $70.4 million in connection with our acquisition of the remaining third party interest in Dixie and $44.9 million in connection with the acquisition of Great Divide. The remaining ownership interests in Dixie were acquired from Amoco Pipeline Holding Company in August 2008. Management attributes the goodwill to future earnings growth on the Dixie Pipeline. Specifically, a 100.0% ownership interest in the Dixie Pipeline will increase our flexibility to pursue future opportunities. Great Divide was acquired from EnCana in December 2008. The Great Divide goodwill is attributable to management's expectations of future benefits derived from incremental natural gas processing margins and other downstream activities. The Dixie and Great Divide goodwill amounts are recorded as part of the NGL Pipelines & Services business segment due to management's belief that such future benefits will accrue to businesses classified within this segment. For additional information see Note 12.

Goodwill recorded in connection with the GulfTerra Merger can be attributed to our belief (at the time the merger was consummated) that the combined partnerships would benefit from the strategic location of each partnership's assets and the industry relationships that each possessed. In addition, we expected that various operating synergies could develop (such as reduced general and administrative costs and interest savings) that would result in improved financial results for the merged entity. Based on miles of pipelines, GulfTerra was one of the largest natural gas gathering and transportation companies in the United States, serving producers in the central and western Gulf of Mexico and onshore in Texas and New Mexico. These regions offer us significant growth potential through the acquisition and construction of additional pipelines, platforms, processing and storage facilities and other midstream energy infrastructure.

Management attributes goodwill recorded in connection with the Encinal acquisition to potential future benefits we may realize from our other south Texas processing and NGL businesses as a result of acquiring the Encinal business. Specifically, our acquisition of the long-term dedication rights associated with the Encinal business is expected to add value to our south Texas processing facilities and related NGL businesses due to increased volumes. The Encinal goodwill is recorded as part of the NGL Pipelines & Services business segment due to management's belief that such future benefits will accrue to businesses classified within this segment.

The remainder of our goodwill amounts is associated with prior acquisitions, principally that of our purchase of a propylene fractionation business in February 2002 and our acquisition of indirect ownership interests in the Indian Springs natural gas gathering and processing business in January 2005.

Note 14. Debt Obligations

Our consolidated debt obligations consisted of the following at the dates indicated:

	At December 31, 2008	At December 31, 2007
EPO senior debt obligations:		
Multi-Year Revolving Credit Facility, variable rate, due November 2012	$ 800,000	$ 725,000
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010	54,000	54,000
Petal GO Zone Bonds, variable rate, due August 2037	57,500	57,500
Yen Term Loan, 4.93% fixed-rate, due March 2009 (1)	217,596	--
Senior Notes B, 7.50% fixed-rate, due February 2011	450,000	450,000
Senior Notes C, 6.375% fixed-rate, due February 2013	350,000	350,000
Senior Notes D, 6.875% fixed-rate, due March 2033	500,000	500,000
Senior Notes F, 4.625% fixed-rate, due October 2009 (1)	500,000	500,000
Senior Notes G, 5.60% fixed-rate, due October 2014	650,000	650,000
Senior Notes H, 6.65% fixed-rate, due October 2034	350,000	350,000
Senior Notes I, 5.00% fixed-rate, due March 2015	250,000	250,000
Senior Notes J, 5.75% fixed-rate, due March 2035	250,000	250,000
Senior Notes K, 4.950% fixed-rate, due June 2010	500,000	500,000
Senior Notes L, 6.30% fixed-rate, due September 2017	800,000	800,000
Senior Notes M, 5.65% fixed-rate, due April 2013	400,000	--
Senior Notes N, 6.50% fixed-rate, due January 2019	700,000	--
Senior Notes O, 9.75% fixed-rate, due January 2014	500,000	--
Duncan Energy Partners' debt obligations:		
DEP I Revolving Credit Facility, variable rate, due February 2011	202,000	200,000
DEP II Term Loan Agreement, variable rate, due December 2011	282,250	--
Dixie Revolving Credit Facility, variable rate, due June 2010 (2)	--	10,000
Total principal amount of senior debt obligations	7,813,346	5,646,500
EPO Junior Subordinated Notes A, fixed/variable rate, due August 2066	550,000	550,000
EPO Junior Subordinated Notes B, fixed/variable rate, due January 2068	682,700	700,000
Total principal amount of senior and junior debt obligations	9,046,046	6,896,500
Other, non-principal amounts:		
Change in fair value of debt-related financial instruments (see Note 7)	51,935	14,839
Unamortized discounts, net of premiums	(7,306)	(5,194)
Unamortized deferred net gains related to terminated interest rate swaps (see Note 7)	17,735	--
Total other, non-principal amounts	62,364	9,645
Total long-term debt	$ 9,108,410	$ 6,906,145
Standby letters of credit outstanding	$ 1,000	$ 1,100

(1) In accordance with SFAS 6, Classification of Short-Term Obligations Expected to be Refinanced, long-term and current maturities of debt reflects the classification of such obligations at December 31, 2008. With respect to the Yen Term Loan and Senior Notes F due in October 2009, we have the ability to use available credit capacity under EPO's Multi-Year Revolving Credit Facility to fund the repayment of this debt.

(2) The Dixie Revolving Credit Facility was terminated in January 2009.

Letters of credit

At December 31, 2008, we had $1.0 million in standby letters outstanding under Duncan Energy Partners' DEP I Revolving Credit Facility. At December 31, 2007, we had $1.1 million of standby letters of credit outstanding under Duncan Energy Partners' DEP I Revolving Credit Facility.

Parent-Subsidiary guarantor relationships

Enterprise Partners Products L.P. acts as guarantor of the consolidated debt obligations of EPO with the exception of the DEP I Revolving Credit Facility and the DEP II Term Loan Agreement. If EPO were to default on any of its guaranteed debt, Enterprise Products Partners L.P. would be responsible for full repayment of that obligation.

EPO's debt obligations

Multi-Year Revolving Credit Facility. In November 2007, EPO executed an amended and restated Multi-Year Revolving Credit Facility totaling $1.75 billion, which replaced an existing $1.25 billion multi-year revolving credit agreement. Amounts borrowed under the amended and restated credit agreement mature in November 2012, although EPO is permitted, 30 to 60 days before the maturity date in effect, to convert the principal balance of the revolving loans then outstanding into a non-revolving, one-year term loan (the "term-out option"). There is no sublimit on the amount of standby letters of credit that can be outstanding under the amended facility. EPO's borrowings under this agreement are unsecured general obligations that are non-recourse to EPGP. We have guaranteed repayment of amounts due under this revolving credit agreement through an unsecured guarantee.

As defined by the credit agreement, variable interest rates charged under this facility bear interest at a Eurodollar rate plus an applicable margin. In addition, EPO is required to pay a quarterly facility fee on each lender's commitment irrespective of commitment usage.

The applicable margins will be increased by 0.10% per annum for each day that the total outstanding loans and letter of credit obligations under the facility exceeds 50.0% of the total lender commitments. Also, upon the conversion of the revolving loans to term loans pursuant to the term-out option described above, the applicable margin will increase by 0.125% per annum and, if immediately prior to such conversion, the total amount of outstanding loans and letter of credit obligations under the facility exceeds 50.0% of the total lender commitments, the applicable margin with respect to the term loans will increase by an additional 0.10% per annum.

EPO may increase the amount that may be borrowed under the facility, without the consent of the lenders, by an amount not exceeding $500.0 million by adding to the facility one or more new lenders and/or requesting that the commitments of existing lenders be increased, although none of the existing lenders has agreed to or is obligated to increase its existing commitment. EPO may request unlimited one-year extensions of the maturity date by delivering a written request to the administrative agent, but any such extension shall be effective only if consented to by the required lenders in their sole discretion.

The Multi-Year Revolving Credit Facility contains various covenants related to EPO's ability to incur certain indebtedness; grant certain liens; enter into certain merger or consolidation transactions; and make certain investments. The loan agreement also requires EPO to satisfy certain financial covenants at the end of each fiscal quarter. The credit agreement also restricts EPO's ability to pay cash distributions to us if a default or an event of default (as defined in the credit agreement) has occurred and is continuing at the time such distribution is scheduled to be paid.

Pascagoula MBFC Loan. In connection with the construction of our Pascagoula, Mississippi natural gas processing plant in 2000, EPO entered into a ten-year fixed-rate loan with the Mississippi Business Finance Corporation ("MBFC"). This loan is subject to a make-whole redemption right and is guaranteed by us through an unsecured and unsubordinated guarantee. The Pascagoula MBFC Loan contains certain covenants including the maintenance of appropriate levels of insurance on the Pascagoula facility.

The indenture agreement for this loan contains an acceleration clause whereby if EPO's credit rating by Moody's declines below Baa3 in combination with our credit rating at Standard & Poor's declining below BBB-, the $54.0 million principal balance of this loan, together with all accrued and unpaid interest, would become immediately due and payable 120 days following such event. If such an event occurred, we would have to either redeem the Pascagoula MBFC Loan or provide an alternative credit agreement to support our obligation under this loan.

Petal GO Zone Bonds. In August 2007, Petal borrowed $57.5 million from the MBFC pursuant to a loan agreement and promissory note between Petal Gas Storage, L.L.C. ("Petal") and the MBFC to pay a portion of the costs of certain natural gas storage facilities located in Petal, Mississippi. The promissory note between Petal and MBFC is guaranteed by EPO and supported by a letter of credit issued by Petal. On the same date, the MBFC issued $57.5 million in Gulf Opportunity Zone Tax-Exempt ("GO Zone") bonds to various third parties. A portion of the GO Zone bond proceeds were being held by a third party trustee and reflected as a component of other assets on our balance sheet. During 2008, virtually all proceeds from the GO Zone bonds were released by the trustee to fund construction costs associated with the expansion of our Petal, Mississippi storage facility. At December 31, 2007, $17.9 million of the GO Zone bond proceeds remained held by the third party trustee. The promissory note and the GO Zone bonds have identical terms including floating interest rates and maturities of 30 years. The bonds and the associated tax incentives are authorized under the Mississippi Business Finance Act and the Gulf Opportunity Zone Act of 2005.

Petal MBFC Loan. In August 2007, Petal, a wholly owned subsidiary of EPO, entered into a loan agreement and a promissory note with the MBFC under which Petal may borrow up to $29.5 million. On the same date, the MBFC issued taxable bonds to EPO in the maximum amount of $29.5 million. As of December 31, 2008, there was $8.9 million outstanding under the loan and the bonds. EPO will make advances on the bonds to the MBFC and the MBFC will in turn make identical advances to Petal under the promissory note. The promissory note and the taxable bonds have identical terms including fixed interest rates of 5.90% and maturities of fifteen years. The bonds and the associated tax incentives are authorized under the Mississippi Business Finance Act. Petal may prepay on the promissory note without penalty, and thus cause the bonds to be redeemed, any time after one year from their date of issue. The loan and bonds are netted in preparing our Consolidated Balance Sheets, as well the related interest expense and income amounts are netted in preparing our Statements of Consolidated Operations.

Japanese Yen Term Loan. In November 2008, EPO executed the Yen Term Loan in the amount of approximately 20.7 billion yen (approximately $217.6 million U.S. Dollar equivalent on the closing date). EPO's obligations under the Yen Term Loan are not secured by any collateral; however, the obligations are guaranteed by Enterprise Products Partners L.P. pursuant to a guaranty agreement. The Yen Term Loan will mature on March 30, 2009.

Under the Yen Term Loan, interest accrues on the loan at the Tokyo Interbank Offered Rate ("TIBOR") plus 2.0%. EPO entered into foreign exchange currency swaps that effectively convert the TIBOR loan into a U.S. Dollar loan with a fixed interest rate (including the cost of the swaps) through maturity of approximately 4.93%. As a result, EPO received US$217.6 million net from this transaction. In addition, EPO executed a forward purchase exchange (yen principal and interest due) for March 30, 2009 at an exchange rate of 94.515 to eliminate foreign exchange risk, resulting in a payment of US$221.6 million on March 30, 2009. For additional information see Note 7.

364-Day Revolving Credit Facility. In November 2008, EPO executed a 364-Day Revolving Credit Agreement ("364-Day Revolving Credit Facility") in the amount of $375.0 million. EPO's obligations under the 364-Day Revolving Credit Facility are not secured by any collateral; however, the obligations are guaranteed by Enterprise Products Partners L.P. pursuant to a guaranty agreement. The 364-Day Revolving Credit Facility will mature on November 16, 2009. As of December 31, 2008, there were no borrowings outstanding under this credit facility.

The 364-Day Revolving Credit Facility offers the following loans, each having different interest requirements: (i) LIBOR loans bear interest at a rate per annum equal to LIBOR plus the applicable LIBOR margin and (ii) Base Rate loans bear interest each day at a rate per annum equal to the higher of (a) the rate of interest announced by the administrative agent as its prime rate, (b) 0.5% per annum above the Federal Funds Rate in effect on such date , and (c) 1.0% per annum above LIBOR in effect on such date plus, in each case, the applicable Base Rate margin.

The commitments may be increased by an amount not to exceed $1.0 billion by adding one or more new lenders to the facility or increasing the commitments of existing lenders, although none of the existing lenders has agreed to or is obligated to increase its existing commitment. With certain exceptions and after certain time periods, if EPO issues debt with a maturity of more than three years, the lenders' commitments under the 364-Day Revolving Credit Facility will be reduced to the extent of any debt proceeds, and any outstanding loans in excess of such reduced commitments must be repaid.

Senior Notes B through L. These fixed-rate notes are unsecured obligations of EPO and rank equally with its existing and future unsecured and unsubordinated indebtedness. They are senior to any future subordinated indebtedness. EPO's borrowings under these notes are non-recourse to EPGP. We have guaranteed repayment of amounts due under these notes through an unsecured and unsubordinated guarantee. Our guarantee of such notes is non-recourse to EPGP. The Senior Notes are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict EPO's ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions.

EPO used net proceeds from its issuance of Senior Notes L in 2007 to temporarily reduce indebtedness outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. In October 2007, EPO used borrowing capacity under its Multi-Year Revolving Credit Facility to repay its $500.0 million Senior Notes E.

Senior Notes M and N. In April 2008, EPO sold $400.0 million in principal amount of 5-year senior unsecured notes ("Senior Notes M") and $700.0 million in principal amount of 10-year senior unsecured notes ("Senior Notes N") under its universal registration statement. Senior Notes M were issued at 99.906% of their principal amount, have a fixed interest rate of 5.65% and mature in April 2013. Senior Notes N were issued at 99.866% of their principal amount, have a fixed interest rate of 6.50% and mature in January 2019.

Senior Notes M pay interest semi-annually in arrears on April 1 and October 1 of each year. Senior Notes N pay interest semi-annually in arrears on January 31 and July 31 of each year. Net proceeds from the issuance of Senior Notes M and N were used to temporarily reduce indebtedness outstanding under the EPO Multi-Year Revolving Credit Facility.

Senior Notes M and N rank equal with EPO's existing and future unsecured and unsubordinated indebtedness. They are senior to any existing and future subordinated indebtedness of EPO. Senior Notes M and N are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict EPO's ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions.

Senior Notes O. In December 2008, EPO sold $500.0 million in principal amount of 5-year senior unsecured notes ("Senior Notes O") under its universal registration statement. Senior Notes O were issued at 100.0% of their principal amount, have a fixed interest rate of 9.75% and mature in January 2014.

Senior Notes O pay interest semi-annually in arrears on January 31 and July 31 of each year, commencing January 31, 2009. Net proceeds from the issuance of Senior Notes O were used to temporarily reduce indebtedness outstanding under the EPO Multi-Year Revolving Credit Facility.

Senior Notes O rank equal with EPO's existing and future unsecured and unsubordinated indebtedness. They are senior to any existing and future subordinated indebtedness of EPO. Senior Notes O are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict EPO's ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions.

Junior Notes A. In the third quarter of 2006, EPO sold $550.0 million in principal amount of fixed/floating, unsecured, long-term subordinated notes due 2066 ("Junior Notes A"). EPO used the proceeds from this subordinated debt to temporarily reduce borrowings outstanding under its Multi-Year

Revolving Credit Facility and for general partnership purposes. EPO's payment obligations under Junior Notes A are subordinated to all of its current and future senior indebtedness (as defined in the related indenture agreement). We guaranteed EPO's repayment of amounts due under Junior Notes A through an unsecured and subordinated guarantee.

The indenture agreement governing Junior Notes A allows EPO to defer interest payments on one or more occasions for up to ten consecutive years, subject to certain conditions. The indenture agreement also provides that, unless (i) all deferred interest on Junior Notes A has been paid in full as of the most recent interest payment date, (ii) no event of default under the indenture agreement has occurred and is continuing and (iii) we are not in default of our obligations under related guarantee agreements, neither we nor EPO cannot declare or make any distributions to any of our respective equity securities or make any payments on indebtedness or other obligations that rank pari passu with or are subordinated to the Junior Notes A.

The Junior Notes A bear interest at a fixed annual rate of 8.375% from July 2006 to August 2016, payable semi-annually in arrears in February and August of each year, which commenced in February 2007. After August 2016, the Junior Notes A will bear variable rate interest at an annual rate equal to the 3-month LIBOR rate for the related interest period plus 3.708%, payable quarterly in arrears in February, May, August and November of each year commencing in November 2016. Interest payments may be deferred on a cumulative basis for up to ten consecutive years, subject to the certain provisions. The Junior Notes A mature in August 2066 and are not redeemable by EPO prior to August 2016 without payment of a make-whole premium.

In connection with the issuance of Junior Notes A, EPO entered into a Replacement Capital Covenant in favor of the covered debt holders (as defined in the underlying documents) pursuant to which EPO agreed for the benefit of such debt holders that it would not redeem or repurchase such junior notes unless such redemption or repurchase is made using proceeds from the issuance of certain securities.

Junior Notes B. EPO sold $700.0 million in principal amount of fixed/floating, unsecured, long-term subordinated notes due January 2068 ("Junior Notes B") during the second quarter of 2007. EPO used the proceeds from this subordinated debt to temporarily reduce borrowings outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. EPO's payment obligations under Junior Notes B are subordinated to all of its current and future senior indebtedness (as defined in the Indenture Agreement). We have guaranteed repayment of amounts due under Junior Notes B through an unsecured and subordinated guarantee.

The indenture agreement governing Junior Notes B allows EPO to defer interest payments on one or more occasions for up to ten consecutive years subject to certain conditions. During any period in which interest payments are deferred and subject to certain exceptions, neither we nor EPO can declare or make any distributions to any of our respective equity securities or make any payments on indebtedness or other obligations that rank pari passu with or are subordinate to Junior Notes B. Junior Notes B rank pari passu with Junior Notes A.

The Junior Notes B will bear interest at a fixed annual rate of 7.034% through January 15, 2018, payable semi-annually in arrears in January and July of each year, which commenced in January 2008. After January 2018, the Junior Notes B will bear variable rate interest at the greater of (1) the sum of the 3-month LIBOR for the related interest period plus a spread of 268 basis points or (2) 7.034% per annum, payable quarterly in arrears in January, April, July and October of each year commencing in April 2018. Interest payments may be deferred on a cumulative basis for up to ten consecutive years, subject to certain provisions. The Junior Notes B mature in January 2068 and are not redeemable by EPO prior to January 2018 without payment of a make-whole premium.

In connection with the issuance of Junior Notes B, we and EPO entered into a Replacement Capital Covenant in favor of the covered debt holders (as named therein) pursuant to which we and EPO agreed for the benefit of such debt holders that neither we nor EPO would redeem or repurchase such junior notes on or before January 15, 2038, unless such redemption or repurchase is made from the proceeds of issuance of certain securities.

During the fourth quarter of 2008, we retired $17.3 million of our Junior Notes B for $10.2 million. The $7.1 million gain on extinguishment of debt is included in "Other, net" on our Statement of Consolidated Operations.

Duncan Energy Partners' debt obligations

We consolidate the debt of Duncan Energy Partners with that of our own; however, we do not have the obligation to make interest payments or debt payments with respect to the debt of Duncan Energy Partners.

DEP I Revolving Credit Facility. In February 2007, Duncan Energy Partners entered into a $300.0 million revolving credit facility, all of which may be used for letters of credit, with a $30.0 million sublimit for Swingline loans. Letters of credit outstanding under this facility reduce the amount available for borrowings. At the closing of its initial public offering, Duncan Energy Partners made its initial borrowing of $200.0 million under the facility to fund a $198.9 million cash distribution to EPO and the remainder to pay debt issuance costs. At December 31, 2008, the principal balance outstanding under this facility was $202.0 million.

This credit facility matures in February 2011 and will be used by Duncan Energy Partners in the future to fund working capital and other capital requirements and for general partnership purposes. Duncan Energy Partners may make up to two requests for one-year extensions of the maturity date (subject to certain restrictions). The revolving credit facility is available to pay distributions upon the initial contribution of assets to Duncan Energy Partners, fund working capital, make acquisitions and provide payment for general purposes. Duncan Energy Partners can increase the revolving credit facility, without consent of the lenders, by an amount not to exceed $150.0 million by adding to the facility one or more new lenders and/or increasing the commitments of existing lenders. No existing lender is required to increase its commitment, unless it agrees to do so in its sole discretion.

This revolving credit facility offers the following unsecured loans, each having different interest requirements: (i) a Eurodollar rate, plus the applicable Eurodollar margin (as defined in the credit agreement), (ii) Base Rate loans bear interest at a rate per annum equal to the higher of (a) the rate of interest publicly announced by the administrative agent, Wachovia Bank, National Association, as its Base Rate and (b) 0.5% per annum above the Federal Funds Rate in effect on such date and (iii) Swingline loans bear interest at a rate per annum equal to LIBOR plus an applicable LIBOR margin.

The Duncan Energy Partners' credit facility contains certain financial and other customary covenants. Also, if an event of default exists under the credit agreement, the lenders will be able to accelerate the maturity date of amounts borrowed under the credit agreement and exercise other rights and remedies.

DEP II Term Loan Agreement. In April 2008, Duncan Energy Partners entered into a standby term loan agreement consisting of commitments for up to a $300.0 million senior unsecured term loan. Subsequently, commitments under this agreement decreased to $282.3 million due to bankruptcy of one of the lenders. Duncan Energy Partners borrowed the full amount of $282.3 million on December 8, 2008 in connection with the acquisition of equity interests in the DEP II Midstream Businesses. See "Relationship with Duncan Energy Partners" in Note 17 for additional information regarding the DEP II Midstream Businesses.

Loans under the term loan agreement are due and payable on December 8, 2011. Duncan Energy Partners may also prepay loans under the term loan agreement at any time, subject to prior notice in accordance with the credit agreement. Loans may also be payable earlier in connection with an event of default.

Loans under the term loan agreement bear interest of the type specified in the applicable borrowing request, and consist of either Alternate Base Rate ("ABR") loans or Eurodollar loans. The term loan agreement contains customary affirmative and negative covenants.

Dixie Revolving Credit Facility

Dixie's debt obligation consisted of a senior, unsecured revolving credit facility having a borrowing capacity of $28.0 million. As of December 31, 2008, there were no debt obligations outstanding under the Dixie Revolver. This credit facility was terminated in January 2009. EPO consolidated the debt of Dixie; however, EPO did not have the obligation to make interest or debt payments with respect to Dixie's debt.

Variable interest rates charged under this facility generally bore interest, at Dixie's election at the time of each borrowing, at either (i) a Eurodollar rate plus an applicable margin or (ii) the greater of (a) the prime rate or (b) the Federal Funds Effective Rate plus 0.5%.

Canadian Debt Obligation

In May 2007, Canadian Enterprise Gas Products, Ltd. ("Canadian Enterprise"), a wholly owned subsidiary of EPO, entered into a $30.0 million Canadian revolving credit facility with The Bank of Nova Scotia. The credit facility, which includes the issuance of letters of credit, matures in October 2011. Letters of credit outstanding under this facility reduce the amount available for borrowings.

Borrowings may be made in Canadian or U.S. dollars. Canadian denominated borrowings may be comprised of Canadian Prime Rate ("CPR") loans or Bankers' Acceptances and U.S. denominated borrowings may be comprised of ABR or Eurodollar loans, each having different interest rate requirements. CPR loans bear interest at a rate determined by reference to the Canadian Prime Rate. ABR loans bear interest at a rate determined by reference to an alternative base rate as defined in the credit agreement. Eurodollar loans bear interest at a rate determined by the LIBOR plus an applicable rate as defined in the credit agreement. Bankers' Acceptances carry interest at the rate for Canadian bankers' acceptances plus an applicable rate as defined in the credit agreement.

The credit facility contains customary covenants and events of default. The restrictive covenants limit Canadian Enterprise from materially changing the nature of its business or operations, dissolving, or completing mergers. A continuing event of default would accelerate the maturity of amounts borrowed under the credit facility. The obligations under the credit facility are guaranteed by EPO. As of December 31, 2008, there were no debt obligations outstanding under this credit facility.

Covenants

We are in compliance with the covenants of our consolidated debt agreements at December 31, 2008 and 2007.

Information regarding variable interest rates paid

The following table shows the range of interest rates paid and weighted-average interest rate paid on our consolidated variable-rate debt obligations during the year ended December 31, 2008.

	Range of Interest Rates Paid	**Weighted-Average Interest Rate Paid**
EPO's Multi-Year Revolving Credit Facility	0.97% to 6.00%	3.54%
DEP I Revolving Credit Facility	1.30% to 6.20%	4.25%
DEP II Term Loan Agreement	2.93% to 2.93%	2.93%
Dixie Revolving Credit Facility	0.81% to 5.50%	3.20%
Petal GO Zone Bonds	0.78% to 7.90%	2.24%

Consolidated debt maturity table

The following table presents the scheduled maturities of principal amounts of our debt obligations for the next five years and in total thereafter.

2009	$ --
2010	554,000
2011	934,250
2012	1,517,596
2013	750,000
Thereafter	5,290,200
Total scheduled principal payments	$ 9,046,046

Debt Obligations of Unconsolidated Affiliates

We have two unconsolidated affiliates with long-term debt obligations. The following table shows (i) our ownership interest in each entity at December 31, 2008, (ii) total debt of each unconsolidated affiliate at December 31, 2008 (on a 100.0% basis to the affiliate) and (iii) the corresponding scheduled maturities of such debt.

	Our Ownership Interest	Total	Scheduled Maturities of Debt 2009	2010	2011	2012	2013	After 2013
Poseidon	36.0%	$ 109,000	$ --	$ --	$ 109,000	$ --	$ --	$ --
Evangeline	49.5%	15,650	5,000	3,150	7,500	--	--	--
Total		$ 124,650	$ 5,000	$ 3,150	$ 116,500	$ --	$ --	$ --

The credit agreements of our unconsolidated affiliates contain various affirmative and negative covenants, including financial covenants. These businesses were in compliance with such covenants at December 31, 2008 and 2007. The credit agreements of our unconsolidated affiliates restrict their ability to pay cash dividends if a default or an event of default (as defined in each credit agreement) has occurred and is continuing at the time such dividend is scheduled to be paid. Cameron Highway repaid its debt obligations during the second quarter of 2007 using pro rata capital contributions from EPO and its joint venture partner in Cameron Highway.

The following information summarizes significant terms of the debt obligations of our unconsolidated affiliates at December 31, 2008:

Poseidon. Poseidon has $109.0 million outstanding under its $150.0 million revolving credit facility that matures in May 2011. Interest rates charged under this revolving credit facility are variable and depend on the ratio of Poseidon's total debt to its earnings before interest, taxes, depreciation and amortization. This credit agreement is secured by substantially all of Poseidon's assets. The variable interest rates charged on this debt at December 31, 2008 and 2007 were 4.31% and 6.62%, respectively.

Evangeline. At December 31, 2008, short and long-term debt for Evangeline consisted of (i) $8.2 million in principal amount of 9.90% fixed-rate Series B senior secured notes due December 2010 and (ii) a $7.5 million subordinated note payable. The Series B senior secured notes are collateralized by Evangeline's property, plant and equipment, proceeds from a gas sales contract, and by a debt service reserve requirement. Scheduled principal repayments on the Series B notes are $5.0 million in 2009 with a final repayment in 2010 of approximately $3.2 million. The trust indenture governing the Series B notes contains covenants such as requirements to maintain certain financial ratios.

Evangeline incurred the subordinated note payable as a result of its acquisition of a contract-based intangible asset in the 1990s. This note is subject to a subordination agreement which prevents the repayment of principal and accrued interest on the note until such time as the Series B noteholders are either fully cash secured through debt service accounts or have been completely repaid. Variable rate interest accrues on the subordinated note at a Eurodollar rate plus 0.5%. The variable interest rates charged on this note at December 31, 2008 and 2007 were 3.20% and 5.88%, respectively. Accrued interest payable related to the subordinated note was $9.8 million and $9.1 million at December 31, 2008 and 2007, respectively.

Note 15. Partners' Equity and Distributions

Our common units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights or privileges available to them under our Fifth Amended and Restated Agreement of Limited Partnership (together with all amendments thereto, the "Partnership Agreement"). We are managed by our general partner, EPGP.

In accordance with the Partnership Agreement, capital accounts are maintained for our general partner and limited partners. The capital account provisions of our Partnership Agreement incorporate principles established for U.S. Federal income tax purposes and are not comparable to the equity accounts reflected under GAAP in our consolidated financial statements.

Our Partnership Agreement sets forth the calculation to be used in determining the amount and priority of cash distributions that our limited partners and general partner will receive. The Partnership Agreement also contains provisions for the allocation of net earnings and losses to our limited partners and general partner. For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall be allocated among the partners in accordance with their respective percentage interests. Normal income and loss allocations according to percentage interests are done only after giving effect to priority earnings allocations in an amount equal to incentive cash distributions allocated to our general partner.

In August 2005, we revised our Partnership Agreement to allow EPGP, at its discretion, to elect not to make its proportionate capital contributions to us in connection with our issuance of limited partner interests, in which case its 2.0% general partner interest would be proportionately reduced. At the time of such offerings, EPGP has historically contributed cash to us to maintain its 2.0% general partner interest. EPGP made such cash contributions to us during the years ended December 31, 2008 and 2007. If EPGP exercises this option in the future, the amount of earnings we allocate to it and the cash distributions it receives from us will be reduced accordingly. If this occurs, EPGP can, under certain conditions, restore its full 2.0% general partner interest by making additional cash contributions to us.

Equity offerings and registration statements

In general, the Partnership Agreement authorizes us to issue an unlimited number of additional limited partner interests and other equity securities for such consideration and on such terms and conditions as may be established by EPGP in its sole discretion (subject, under certain circumstances, to the approval of our unitholders).

In August 2007, we filed a universal shelf registration statement with the SEC that allows us to issue an unlimited amount of debt and equity securities. In January 2009, we sold 10,590,000 common units (including an over-allotment of 990,000 common units) to the public at an offering price of $22.20 per unit under this universal shelf registration. See Note 25 for additional information.

During 2003, we instituted a distribution reinvestment plan ("DRIP"). In April 2007, we filed a registration statement with the SEC authorizing the issuance of up to 25,000,000 common units in connection with the DRIP. The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional common units. A total of 21,471,047 common units have been issued under this registration statement through December 31, 2008.

We also have a registration statement on file related to our employee unit purchase plan ("EUPP"), under which we can issue up to 1,200,000 common units. Under this plan, employees of EPCO can purchase our common units at a 10.0% discount through payroll deductions. A total of 651,297 common units have been issued to employees under this plan through December 31, 2008.

The following table reflects the number of common units issued and the net proceeds received from underwritten and other common unit offerings completed during the years ended December 31, 2008, 2007 and 2006:

	Net Proceeds from Sale of Common Units			
	Number of Common Units Issued	Contributed by Limited Partners	Contributed by General Partner	Total Net Proceeds
Fiscal 2006:				
Underwritten offerings	31,050,000	$ 735,819	$ 15,003	$ 750,822
DRIP and EUPP	3,774,649	95,006	1,940	96,946
Total 2006	34,824,649	$ 830,825	$ 16,943	$ 847,768
Fiscal 2007:				
DRIP and EUPP	2,056,615	$ 60,445	$ 1,232	$ 61,677
Total 2007	2,056,615	$ 60,445	$ 1,232	$ 61,677
Fiscal 2008:				
DRIP and EUPP	5,523,946	$ 139,248	$ 2,842	$ 142,090
Total 2008	5,523,946	$ 139,248	$ 2,842	$ 142,090

Net proceeds received from our underwritten and other offerings completed during 2006 were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

Net proceeds received from our DRIP and EUPP were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

Summary of Changes in Outstanding Units

The following table summarizes changes in our outstanding units since December 31, 2005:

	Common Units	Restricted Common Units	Treasury Units
Balance, December 31, 2005	389,109,564	751,604	--
Common units issued in connection with underwritten offerings	31,050,000	--	--
Common units issued in connection with DRIP and EUPP	3,774,649	--	--
Common units issued in connection with equity awards	211,000	466,400	--
Forfeiture of restricted units	--	(70,631)	--
Conversion of restricted units to common units	42,136	(42,136)	--
Common units issued in connection with Encinal acquisition	7,115,844	--	--
Balance, December 31, 2006	431,303,193	1,105,237	--
Common units issued in connection with DRIP and EUPP	2,056,615	--	--
Common units issued in connection with equity awards	244,071	738,040	--
Forfeiture or settlement of restricted units	--	(149,853)	--
Conversion of restricted units to common units	4,884	(4,884)	--
Balance, December 31, 2007	433,608,763	1,688,540	--
Common units issued in connection with DRIP and EUPP	5,523,946	--	--
Common units issued in connection with equity awards	21,905	--	--
Restricted units issued	--	766,200	--
Forfeiture or settlement of restricted units	--	(88,777)	--
Conversion of restricted units to common units	285,363	(285,363)	--
Acquisition of treasury units	(85,246)	--	85,246
Cancellation of treasury units	--	--	(85,246)
Balance, December 31, 2008	439,354,731	2,080,600	--

Treasury Units. In 2000, we and a consolidated trust (the "1999 Trust") were authorized by EPGP to repurchase up to 2,000,000 publicly-held common units under an announced buy-back program. The repurchases would be made during periods of temporary market weakness at price levels that would be accretive to our remaining unitholders. After deducting for repurchases under the program in prior periods, we and the 1999 Trust could repurchase up to 618,400 common units at December 31, 2008.

During the year ended December 31, 2008, 285,363 restricted unit awards vested and were converted to common units. Of this amount, 85,246 were sold back to us by employees to cover related withholding tax requirements. The total cost of these treasury units was approximately $1.9 million, of which a minimal amount was allocated to our general partner. Immediately upon acquisition, we cancelled such treasury units.

Summary of Changes in Limited Partners' Equity

The following table details the changes in limited partners' equity since December 31, 2005:

	Common Units	Restricted Common Units	Total
Balance, December 31, 2005	$ 5,542,700	$ 18,638	$ 5,561,338
Net income	502,969	1,187	504,156
Operating leases paid by EPCO	2,062	5	2,067
Cash distributions to partners	(738,004)	(1,628)	(739,632)
Unit option reimbursements to EPCO	(1,818)	--	(1,818)
Net proceeds from issuance of common units	830,825	--	830,825
Common units issued in connection with Encinal acquisition	181,112	--	181,112
Proceeds from exercise of unit options	5,601		5,601
Amortization of equity awards	2,209	6,073	8,282
Change in accounting method for equity awards (see Note 5)	(896)	(14,919)	(15,815)
Acquisition-related disbursement of cash	(6,183)	(16)	(6,199)
Balance, December 31, 2006	6,320,577	9,340	6,329,917
Net income	416,323	1,405	417,728
Operating leases paid by EPCO	2,056	7	2,063
Cash distributions to partners	(831,155)	(2,638)	(833,793)
Unit option reimbursements to EPCO	(2,999)	--	(2,999)
Net proceeds from issuance of common units	60,445	--	60,445
Proceeds from exercise of unit options	7,549	--	7,549
Repurchase of restricted units and options	(512)	(1,056)	(1,568)
Amortization of equity awards	4,663	8,890	13,553
Balance, December 31, 2007	5,976,947	15,948	5,992,895
Net income	807,894	3,653	811,547
Operating leases paid by EPCO	1,988	9	1,997
Cash distributions to partners	(888,802)	(3,891)	(892,693)
Unit option reimbursements to EPCO	(550)	--	(550)
Non-cash distributions	(7,140)	--	(7,140)
Acquisition of treasury units, limited partner share	--	(1,873)	(1,873)
Net proceeds from issuance of common units	139,248	--	139,248
Proceeds from exercise of unit options	679	--	679
Amortization of equity awards	6,623	12,373	18,996
Balance, December 31, 2008	$ 6,036,887	$ 26,219	$ 6,063,106

In October 2006, we acquired all of the capital stock of an affiliated NGL marketing company located in Canada from EPCO and Dan L. Duncan for $17.7 million in cash. The amount we paid for this business exceeded the carrying values of the assets acquired and liabilities assumed from this related party (which is under common control with us) by $6.3 million, of which $6.2 million was allocated to limited partners and $0.1 million to our general partner. The excess of the acquisition price over the net book value of this business at the time of acquisition is treated as a deemed distribution to our owners and presented as an "Acquisition-related disbursement of cash" in our Statement of Partners' Equity for the year ended

December 31, 2006. The total purchase price is a component of "Cash used for business combinations" as presented in our Statement of Consolidated Cash Flows for the year ended December 31, 2006.

Distributions to Partners

The percentage interest of EPGP in our quarterly cash distributions is increased after certain specified target levels of quarterly distribution rates are met. At current distribution rates, we are in the highest tier of such incentive targets. EPGP's quarterly incentive distribution thresholds are as follows:

- 2.0% of quarterly cash distributions up to $0.253 per unit;
- 15.0% of quarterly cash distributions from $0.253 per unit up to $0.3085 per unit; and
- 25.0% of quarterly cash distributions that exceed $0.3085 per unit.

We paid incentive distributions of $125.9 million, $107.4 million and $86.7 million to EPGP during the years ended December 31, 2008, 2007 and 2006, respectively.

The following table presents our declared quarterly cash distribution rates per unit since the first quarter of 2007 and the related record and distribution payment dates. The quarterly cash distribution rates per unit correspond to the fiscal quarters indicated. Actual cash distributions are paid within 45 days after the end of such fiscal quarter.

	Distribution per Unit	**Record Date**	**Payment Date**
2007			
1st Quarter	$0.4750	Apr. 30, 2007	May 10, 2007
2nd Quarter	$0.4825	Jul. 31, 2007	Aug. 9, 2007
3rd Quarter	$0.4900	Oct. 31, 2007	Nov. 8, 2007
4th Quarter	$0.5000	Jan. 31, 2008	Feb. 7, 2008
2008			
1st Quarter	$0.5075	Apr. 30, 2008	May 7, 2008
2nd Quarter	$0.5150	Jul. 31, 2008	Aug. 7, 2008
3rd Quarter	$0.5225	Oct. 31, 2008	Nov. 12, 2008
4th Quarter	$0.5300	Jan. 30, 2009	Feb. 9, 2009

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) primarily includes the effective portion of the gain or loss on financial instruments designated and qualified as a cash flow hedge, foreign currency adjustments and Dixie's minimum pension liability adjustments. Amounts accumulated in other comprehensive income (loss) from cash flow hedges are reclassified into earnings in the same period(s) in which the hedged forecasted transactions (such as a forecasted forward sale of NGLs) affect earnings. If it becomes probable that the forecasted transaction will not occur, the net gain or loss in accumulated other comprehensive income (loss) must be immediately reclassified.

The following table presents the components of accumulated other comprehensive income (loss) at the dates indicated:

	At December 31,	
	2008	**2007**
Commodity financial instruments – cash flow hedges (1)	$ (114,077)	$ (21,619)
Interest rate financial instruments – cash flow hedges (1)	3,818	34,980
Foreign currency cash flow hedges (1)	10,594	1,308
Foreign currency translation adjustment (2)	(1,301)	1,200
Pension and postretirement benefit plans (3)	(751)	588
Total accumulated other comprehensive income (loss)	$ (101,717)	$ 16,457

(1) See Note 7 for additional information regarding these components of accumulated other comprehensive income (loss).
(2) Relates to transactions of our Canadian NGL marketing subsidiary.
(3) See Note 6 for additional information regarding pension and postretirement benefit plans.

Note 16. Business Segments

We have four reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Offshore Pipelines & Services and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our senior management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered an alternative to GAAP operating income.

We define total segment gross operating margin as consolidated operating income before: (i) depreciation, amortization and accretion expense; (ii) operating lease expenses for which we do not have the payment obligation; (iii) gains and losses from asset sales and related transactions; and (iv) general and administrative costs. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest, extraordinary charges and the cumulative effect of change in accounting principle. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intersegment and intrasegment transactions.

Segment revenues include intersegment and intrasegment transactions, which are generally based on transactions made at market-related rates. Our consolidated revenues reflect the elimination of intercompany (both intersegment and intrasegment) transactions.

We include equity in earnings of unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers and/or suppliers. This method of operation enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand alone basis. Many of these businesses perform supporting or complementary roles to our other business operations.

Our integrated midstream energy asset system (including the midstream energy assets of our equity method investees) provides services to producers and consumers of natural gas, NGLs, crude oil and certain petrochemicals. In general, hydrocarbons enter our asset system in a number of ways, such as an offshore natural gas or crude oil pipeline, an offshore platform, a natural gas processing plant, an onshore natural gas gathering pipeline, an NGL fractionator, an NGL storage facility, or an NGL transportation or distribution pipeline.

Many of our equity investees are included within our integrated midstream asset system. For example, we have ownership interests in several offshore natural gas and crude oil pipelines. Other examples include our use of the Promix NGL fractionator to process mixed NGLs extracted by our gas plants. The fractionated NGLs we receive from Promix can then be sold in our NGL marketing activities. Given the integral nature of our equity method investees to our operations, we believe the presentation of earnings from such investees as a component of gross operating margin and operating income is meaningful and appropriate.

Historically, substantially all of our consolidated revenues were earned in the United States and derived from a wide customer base. The majority of our plant-based operations are located in Texas, Louisiana, Mississippi, New Mexico, Colorado and Wyoming. Our natural gas, NGL and crude oil pipelines are located in a number of regions of the United States including (i) the Gulf of Mexico offshore Texas and Louisiana; (ii) the south and southeastern United States (primarily in Texas, Louisiana, Mississippi and Alabama); and (iii) certain regions of the central and western United States, including the Rocky Mountains. Our marketing activities are headquartered in Houston, Texas and serve customers in a number of regions of the United States including the Gulf Coast, West Coast and Mid-Continent areas.

Consolidated property, plant and equipment and investments in and advances to unconsolidated affiliates are assigned to each segment on the basis of each asset's or investment's principal operations. The principal reconciling difference between consolidated property, plant and equipment and the total value of segment assets is construction in progress. Segment assets represent the net book carrying value of facilities and other assets that contribute to gross operating margin of that particular segment. Since assets under construction generally do not contribute to segment gross operating margin, such assets are excluded from segment asset totals until they are placed in service. Consolidated intangible assets and goodwill are assigned to each segment based on the classification of the assets to which they relate.

We consolidate the financial statements of Duncan Energy Partners with those of our own. As a result, our consolidated gross operating margin amounts include 100.0% of the gross operating margin amounts of Duncan Energy Partners.

The following table shows our measurement of total segment gross operating margin for the periods indicated:

		For the Year Ended December 31,		
		2008	2007	2006
Revenues (1)		$ 21,905,656	$ 16,950,125	$ 13,990,969
Less:	Operating costs and expenses (1)	(20,460,964)	(16,009,051)	(13,089,091)
Add:	Equity in earnings of unconsolidated affiliates (1)	59,104	29,658	21,565
	Depreciation, amortization and accretion in operating costs and expenses (2)	555,370	513,840	440,256
	Operating lease expenses paid by EPCO (2)	2,038	2,105	2,109
	Loss (gain) from asset sales and related transactions in operating costs and expenses (2)	(3,735)	5,391	(3,359)
Total segment gross operating margin		$ 2,057,469	$ 1,492,068	$ 1,362,449

(1) These amounts are taken from our Statements of Consolidated Operations.
(2) These non-cash expenses are taken from the operating activities section of our Statements of Consolidated Cash Flows.

A reconciliation of our total segment gross operating margin to operating income and income before provision for income taxes, minority interest and the cumulative effect of change in accounting principle follows:

	For the Year Ended December 31,		
	2008	2007	2006
Total segment gross operating margin	$ 2,057,469	$ 1,492,068	$ 1,362,449
Adjustments to reconcile total segment gross operating margin to operating income:			
Depreciation, amortization and accretion in operating costs and expenses	(555,370)	(513,840)	(440,256)
Operating lease expense paid by EPCO	(2,038)	(2,105)	(2,109)
Gain (loss) from asset sales and related transactions in operating costs and expenses	3,735	(5,391)	3,359
General and administrative costs	(90,550)	(87,695)	(63,391)
Operating income	1,413,246	883,037	860,052
Other expense, net	(391,448)	(303,463)	(229,967)
Income before provision for income taxes, minority interest and cumulative effect of change in accounting principle	$ 1,021,798	$ 579,574	$ 630,085

Information by segment, together with reconciliations to our consolidated totals, is presented in the following table:

	Reportable Segments					
	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Offshore Pipelines & Services	Petrochemical Services	Adjustments and Eliminations	Consolidated Totals
Revenues from third parties:						
Year ended December 31, 2008	$ 14,664,707	$ 3,161,014	$ 260,288	$ 2,683,197	$ --	$ 20,769,206
Year ended December 31, 2007	12,101,715	1,788,219	222,642	2,184,833	--	16,297,409
Year ended December 31, 2006	10,079,534	1,407,872	144,065	1,956,268	--	13,587,739
Revenues from related parties:						
Year ended December 31, 2008	717,244	411,084	8,122	--	--	1,136,450
Year ended December 31, 2007	369,654	281,876	1,169	17	--	652,716
Year ended December 31, 2006	110,409	291,023	1,798	--	--	403,230
Intersegment and intrasegment revenues:						
Year ended December 31, 2008	7,947,889	833,931	1,418	639,142	(9,422,380)	--
Year ended December 31, 2007	5,346,571	191,741	1,959	514,852	(6,055,123)	--
Year ended December 31, 2006	4,131,776	113,132	1,679	383,754	(4,630,341)	--
Total revenues:						
Year ended December 31, 2008	23,329,840	4,406,029	269,828	3,322,339	(9,422,380)	21,905,656
Year ended December 31, 2007	17,817,940	2,261,836	225,770	2,699,702	(6,055,123)	16,950,125
Year ended December 31, 2006	14,321,719	1,812,027	147,542	2,340,022	(4,630,341)	13,990,969
Equity in earnings of unconsolidated affiliates:						
Year ended December 31, 2008	1,430	22,959	33,609	1,106	--	59,104
Year ended December 31, 2007	6,031	9,540	12,628	1,459	--	29,658
Year ended December 31, 2006	5,715	2,872	11,909	1,069	--	21,565
Gross operating margin by individual business segment and in total:						
Year ended December 31, 2008	1,290,458	411,344	188,083	167,584	--	2,057,469
Year ended December 31, 2007	812,521	335,683	171,551	172,313	--	1,492,068
Year ended December 31, 2006	752,548	333,399	103,407	173,095	--	1,362,449
Segment assets:						
At December 31, 2008	5,424,134	4,033,312	1,394,480	698,157	1,604,691	13,154,774
At December 31, 2007	4,570,555	3,702,297	1,452,568	687,856	1,173,988	11,587,264
Investments in and advances to unconsolidated affiliates (see Note 11):						
At December 31, 2008	144,182	283,981	504,843	16,520	--	949,526
At December 31, 2007	117,089	239,327	484,588	17,335	--	858,339
Intangible assets, net (see Note 13):						
At December 31, 2008	351,010	333,462	116,219	54,725	--	855,416
At December 31, 2007	373,071	354,152	133,058	56,719	--	917,000
Goodwill (see Note 13):						
At December 31, 2008	268,938	282,121	82,135	73,690	--	706,884
At December 31, 2007	153,706	282,121	82,135	73,690	--	591,652

Our revenues are derived from a wide customer base. During 2008 our largest customer was LyondellBasell Industries ("LBI") and its affiliates, which accounted for 9.6% of our consolidated revenues. See Note 21 for additional information regarding our credit exposure to LBI's bankruptcy filing in January 2009. In 2007 and 2006, our largest customer was The Dow Chemical Company and its affiliates, which accounted for 6.9% and 6.1%, respectively, of our consolidated revenues.

On January 6, 2009, LBI announced that its U.S. operations had voluntarily filed to reorganize under Chapter 11 of the U.S. Bankruptcy Code. At the time of the bankruptcy filing, we had approximately $17.3 million of credit exposure to LBI, which was reduced to approximately $10.0 million through remedies provided under certain pipeline tariffs. In addition, we are seeking to have LBI accept certain contracts and have filed claims pursuant to current Bankruptcy Court Orders that we expect will allow us to recover the majority of the remaining credit exposure.

For 2008, LBI accounted for 10.2%, or $1.6 billion, of revenues attributable to our NGL Pipelines & Services business segment and 19.2%, or $516.2 million, of revenues attributable to our Petrochemical Services business segment.

The following table provides additional information regarding our consolidated revenues (net of adjustments and eliminations) and expenses for the periods noted:

	For the Year Ended December 31,		
	2008	2007	2006
NGL Pipelines & Services:			
Sales of NGLs	$ 14,680,607	$ 11,757,895	$ 9,442,403
Sales of other petroleum and related products	2,387	3,027	2,353
Midstream services	698,957	710,447	745,187
Total	15,381,951	12,471,369	10,189,943
Onshore Natural Gas Pipelines & Services:			
Sales of natural gas	3,091,296	1,481,569	1,103,169
Midstream services	480,802	588,526	595,726
Total	3,572,098	2,070,095	1,698,895
Offshore Pipelines & Services:			
Sales of natural gas	100	101	307
Sales of other petroleum and related products	11,144	12,086	4,562
Midstream services	257,166	211,624	140,994
Total	268,410	223,811	145,863
Petrochemical Services:			
Sales of other petroleum and related products	2,593,856	2,115,429	1,873,722
Midstream services	89,341	69,421	82,546
Total	2,683,197	2,184,850	1,956,268
Total consolidated revenues	$ 21,905,656	$ 16,950,125	$ 13,990,969
Consolidated cost and expenses			
Operating costs and expenses:			
Cost of sales	$ 18,662,263	$ 14,509,220	$ 11,778,928
Depreciation, amortization and accretion	555,370	513,840	440,256
Loss (gain) on sale of assets and related transactions	(3,735)	5,391	(3,359)
Other operating costs and expenses	1,247,066	980,600	873,266
General and administrative costs	90,550	87,695	63,391
Total consolidated costs and expenses	$ 20,551,514	$ 16,096,746	$ 13,152,482

Note 17. Related Party Transactions

The following table summarizes our related party transactions for the periods indicated.

	For the Year Ended December 31,		
	2008	2007	2006
Revenues from consolidated operations			
EPCO and affiliates	$ 121,201	$ 67,635	$ 98,671
Energy Transfer Equity and subsidiaries	618,370	294,441	--
Unconsolidated affiliates	396,879	290,640	304,559
Total	$ 1,136,450	$ 652,716	$ 403,230
Cost of sales			
EPCO and affiliates	$ 59,173	$ 33,827	$ 86,050
Energy Transfer Equity and subsidiaries	173,875	26,889	--
Unconsolidated affiliates	90,836	41,474	42,166
Total	$ 323,884	$ 102,190	$ 128,216
Operating costs and expenses			
EPCO and affiliates	$ 314,612	$ 260,716	$ 225,487
Energy Transfer Equity and subsidiaries	18,284	8,267	--
Unconsolidated affiliates	(10,388)	(8,709)	(10,560)
Total	$ 322,508	$ 260,274	$ 214,927
General and administrative expenses			
EPCO and affiliates	$ 59,058	$ 56,518	$ 41,265
Unconsolidated affiliates	(51)	--	--
Total	$ 59,007	$ 56,518	$ 41,265
Other income (expense)			
EPCO and affiliates	$ (274)	$ (170)	$ 680
Unconsolidated affiliates	--	--	262
Total	$ (274)	$ (170)	$ 942

We believe that the terms and provisions of our related party agreements are fair to us; however, such agreements and transactions may not be as favorable to us as we could have obtained from unaffiliated third parties.

Relationship with EPCO and affiliates

We have an extensive and ongoing relationship with EPCO and its affiliates, which include the following significant entities that are not a part of our consolidated group of companies:

- EPCO and its private company subsidiaries;
- EPGP, our sole general partner;
- Enterprise GP Holdings, which owns and controls our general partner;
- TEPPCO, which is owned and controlled by Enterprise GP Holdings; and
- the Employee Partnerships (see Note 5).

We also have an ongoing relationship with Duncan Energy Partners, the financial statements of which are consolidated with those of our own. Our transactions with Duncan Energy Partners are eliminated in consolidation. A description of our relationship with Duncan Energy Partners is presented within this Note 17.

EPCO is a private company controlled by Dan L. Duncan, who is also a Director and Chairman of EPGP, our general partner. At December 31, 2008, EPCO and its affiliates beneficially owned 152,506,527 (or 34.5%) of our outstanding common units, which includes 13,670,925 of our common units owned by Enterprise GP Holdings. In addition, at December 31, 2008, EPCO and its affiliates beneficially owned 77.8% of the limited partner interests of Enterprise GP Holdings and 100.0% of its general partner, EPE Holdings. Enterprise GP Holdings owns all of the membership interests of EPGP. The principal business activity of EPGP is to act as our managing partner. The executive officers and certain of the directors of EPGP and EPE Holdings are employees of EPCO.

As our general partner, EPGP received cash distributions of $144.1 million, $124.4 million and $101.8 million from us during the years ended December 31, 2008, 2007 and 2006, respectively. These amounts include incentive distributions of $125.9 million, $107.4 million and $86.7 million for the years ended December 31, 2008, 2007 and 2006, respectively.

We and EPGP are both separate legal entities apart from each other and apart from EPCO, Enterprise GP Holdings and their respective other affiliates, with assets and liabilities that are separate from those of EPCO, Enterprise GP Holdings and their respective other affiliates. EPCO and its private company subsidiaries depend on the cash distributions they receive from us, Enterprise GP Holdings and other investments to fund their other operations and to meet their debt obligations. EPCO and its private company affiliates received $405.2 million, $355.5 million and $306.5 million in cash distributions from us and Enterprise GP Holdings during the years ended December 31, 2008, 2007 and 2006, respectively.

The ownership interests in us that are owned or controlled by Enterprise GP Holdings are pledged as security under its credit facility. In addition, substantially all of the ownership interests in us that are owned or controlled by EPCO and its affiliates, other than those interests owned by Enterprise GP Holdings, Dan Duncan LLC and certain trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of a private company affiliate of EPCO. This credit facility contains customary and other events of default relating to EPCO and certain affiliates, including Enterprise GP Holdings, TEPPCO and us.

We have entered into an agreement with an affiliate of EPCO to provide trucking services to us for the transportation of NGLs and other products. For the years ended December 31, 2008, 2007 and 2006, we paid this trucking affiliate $21.7 million, $17.5 million and $20.7 million, respectively, for such services.

We lease office space in various buildings from affiliates of EPCO. The rental rates in these lease agreements approximate market rates. For the years ended December 31, 2008, 2007 and 2006, we paid EPCO $5.3 million, $5.6 million and $3.0 million, respectively, for office space leases.

Historically, we entered into transactions with a Canadian affiliate of EPCO for the purchase and sale of NGL products in the normal course of business. These transactions were at market-related prices. We acquired this affiliate in October 2006 and began consolidating its financial statements with those of our own from the date of acquisition. For the nine months ended September 30, 2006, our revenues from this former unconsolidated affiliate were $55.8 million and our purchases were $43.4 million.

EPCO ASA

We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to the ASA. We, Duncan Energy Partners, Enterprise GP Holdings, TEPPCO and our respective general partners are parties to the ASA. The significant terms of the ASA are as follows:

- EPCO will provide selling, general and administrative services, and management and operating services, as may be necessary to manage and operate our businesses, properties and assets (all in accordance with prudent industry practices). EPCO will employ or otherwise retain the services of such personnel as may be necessary to provide such services.

- We are required to reimburse EPCO for its services in an amount equal to the sum of all costs and expenses incurred by EPCO which are directly or indirectly related to our business or activities (including expenses reasonably allocated to us by EPCO). In addition, we have agreed to pay all sales, use, excise, value added or similar taxes, if any, that may be applicable from time to time in respect of the services provided to us by EPCO.

- EPCO will allow us to participate as a named insured in its overall insurance program, with the associated premiums and other costs being allocated to us.

Under the ASA, EPCO subleases to us (for $1 per year) certain equipment which it holds pursuant to operating leases and has assigned to us its purchase option under such leases (the "retained leases"). EPCO remains liable for the actual cash lease payments associated with these agreements. We record the full value of these payments made by EPCO on our behalf as a non-cash related party operating lease expense, with the offset to partners' equity accounted for as a general contribution to our partnership. We exercised our election under the retained leases to purchase a cogeneration unit in December 2008 for $2.3 million. Should we decide to exercise the purchase option associated with the remaining agreement, we would pay the original lessor $3.1 million in June 2016.

Our operating costs and expenses for the years ended December 31, 2008, 2007 and 2006 include reimbursement payments to EPCO for the costs it incurs to operate our facilities, including compensation of employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets. These reimbursements were $329.7 million, $273.0 million and $285.4 million during the years ended December 31, 2008, 2007 and 2006, respectively.

Likewise, our general and administrative costs for the years ended December 31, 2008, 2007 and 2006 include amounts we reimburse to EPCO for administrative services, including compensation of employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to ASA based on the estimated use of such services by each party (e.g., the allocation of general legal or accounting salaries based on estimates of time spent on each entity's business and affairs). These reimbursements were $59.1 million, $56.5 million and $41.3 million during the years ended December 31, 2008, 2007 and 2006, respectively.

Since the vast majority of such expenses are charged to us on an actual basis (i.e. no mark-up or subsidy is charged or received by EPCO), we believe that such expenses are representative of what the amounts would have been on a stand alone basis. With respect to allocated costs, we believe that the proportional direct allocation method employed by EPCO is reasonable and reflective of the estimated level of costs we would have incurred on a standalone basis.

The ASA also addresses potential conflicts that may arise among Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), Duncan Energy Partners (including DEP GP), and the EPCO Group with respect to business opportunities with third parties. The EPCO Group includes EPCO and its other affiliates, but excludes Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners and their respective general partners. With respect to potential conflicts with respect to third party business opportunities, the ASA provides, among other things, that:

- If a business opportunity to acquire "equity securities" (as defined below) is presented to the EPCO Group, Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), Duncan Energy Partners (including DEP GP), then Enterprise GP Holdings will have the first right to pursue such opportunity. The term "equity securities" is defined to include:

    - general partner interests (or securities which have characteristics similar to general partner interests) or interests in "persons" that own or control such general partner or similar interests (collectively, "GP Interests") and securities convertible, exercisable, exchangeable or otherwise representing ownership or control of such GP Interests; and

    - IDRs and limited partner interests (or securities which have characteristics similar to IDRs or limited partner interests) in publicly traded partnerships or interests in "persons" that own or control such limited partner or similar interests (collectively, "non-GP Interests"); provided that such non-GP Interests are associated with GP Interests and are owned by the owners of GP Interests or their respective affiliates.

Enterprise GP Holdings will be presumed to want to acquire the equity securities until such time as EPE Holdings advises the EPCO Group, EPGP and DEP GP that it has abandoned the pursuit of such business opportunity. In the event that the purchase price of the equity securities is reasonably likely to equal or exceed $100.0 million, the decision to decline the acquisition will be made by the chief executive officer of EPE Holdings after consultation with and subject to the approval of the ACG Committee of EPE Holdings. If the purchase price is reasonably likely to be less than $100.0 million, the chief executive officer of EPE Holdings may make the determination to decline the acquisition without consulting the ACG Committee of EPE Holdings.

In the event that Enterprise GP Holdings abandons the acquisition and so notifies the EPCO Group, EPGP and DEP GP, Enterprise Products Partners will have the second right to pursue such acquisition. Enterprise Products Partners will be presumed to want to acquire the equity securities until such time as EPGP advises the EPCO Group and DEP GP that Enterprise Products Partners has abandoned the pursuit of such acquisition. In determining whether or not to pursue the acquisition, Enterprise Products Partners will follow the same procedures applicable to Enterprise GP Holdings, as described above but utilizing EPGP's chief executive officer and ACG Committee.

In its sole discretion, Enterprise Products Partners may affirmatively direct such acquisition opportunity to Duncan Energy Partners. In the event this occurs, Duncan Energy Partners may pursue such acquisition.

In the event Enterprise Products Partners abandons the acquisition opportunity for the equity securities and so notifies the EPCO Group and DEP GP, the EPCO Group may pursue the acquisition or offer the opportunity to TEPPCO (including TEPPCO GP) and their controlled affiliates, in either case, without any further obligation to any other party or offer such opportunity to other affiliates.

- If any business opportunity not covered by the preceding bullet point (i.e. not involving equity securities) is presented to the EPCO Group, Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), or Duncan Energy Partners (including DEP GP), Enterprise Products Partners will have the first right to pursue such opportunity either for itself or, if desired by Enterprise Products Partners in its sole discretion, for the benefit of Duncan Energy Partners. It will be presumed that Enterprise Products Partners will pursue the business opportunity until such time as its general partner advises the EPCO Group, EPE Holdings and DEP GP that it has abandoned the pursuit of such business opportunity.

  In the event the purchase price or cost associated with the business opportunity is reasonably likely to equal or exceed $100.0 million, any decision to decline the business opportunity will be made by the chief executive officer of EPGP after consultation with and subject to the approval of the ACG Committee of EPGP. If the purchase price or cost is reasonably likely to be less than $100.0 million, the chief executive officer of EPGP may make the determination to decline the business opportunity without consulting EPGP's ACG Committee.

  In its sole discretion, Enterprise Products Partners may affirmatively direct such acquisition opportunity to Duncan Energy Partners. In the event this occurs, Duncan Energy Partners may pursue such acquisition.

  In the event that Enterprise Products Partners abandons the business opportunity for itself and Duncan Energy Partners and so notifies the EPCO Group, EPE Holdings and DEP GP, Enterprise GP Holdings will have the second right to pursue such business opportunity. It will be presumed that Enterprise GP Holdings will pursue such acquisition until such time as its general partner declines such opportunity (in accordance with the procedures described above for Enterprise

Products Partners) and advises the EPCO Group that it has abandoned the pursuit of such business opportunity. Should this occur, the EPCO Group may either pursue the business opportunity or offer the business opportunity to TEPPCO (including TEPPCO GP) and their controlled affiliates without any further obligation to any other party or offer such opportunity to other affiliates.

None of Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners or their respective general partners or the EPCO Group have any obligation to present business opportunities to TEPPCO (including TEPPCO GP) or their controlled affiliates. Likewise, TEPPCO (including TEPPCO GP) and their controlled affiliates have no obligation to present business opportunities to Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners or their respective general partners or the EPCO Group.

The ASA was amended on January 30, 2009 to provide for the cash reimbursement by us and Enterprise GP Holdings to EPCO of distributions of cash or securities, if any, made by EPCO Unit to its Class B limited partners. The ASA amendment also extended the term under which EPCO provides services to the partnership entities from December 2010 to December 2013 and made other updating and conforming changes.

Employee Partnerships. EPCO formed the Employee Partnerships to serve as an incentive arrangement for key employees of EPCO by providing them a "profits interest" in such partnerships. Certain EPCO employees who work on behalf of us and EPCO were issued Class B limited partner interests and admitted as Class B limited partners without any capital contribution. The profits interest awards (i.e., the Class B limited partner interests) in the Employee Partnerships entitles each holder to participate in the appreciation in value of our common units, Enterprise GP Holdings' units, or both. See Note 5 for additional information regarding the Employee Partnerships.

Relationship with TEPPCO

TEPPCO became a related party to us in February 2005 when its general partner was acquired by private company affiliates of EPCO. Our relationship was further reinforced by the acquisition of TEPPCO's general partner by Enterprise GP Holdings in May 2007. Enterprise GP Holdings also owns our general partner.

We received $121.2 million, $67.6 million and $42.9 million from TEPPCO during the years ended December 31, 2008, 2007 and 2006, respectively, from the sale of hydrocarbon products. We paid TEPPCO $42.0 million, $19.4 million and $24.0 million for NGL pipeline transportation and storage services during the years ended December 31, 2008, 2007 and 2006, respectively.

Purchase of Pioneer I plant from TEPPCO. In March 2006, we paid TEPPCO $38.2 million for its Pioneer I natural gas processing plant located in Opal, Wyoming and certain natural gas processing rights related to natural gas production from the Jonah and Pinedale fields located in the Greater Green River Basin in Wyoming. After an in-depth consideration of all relevant factors, this transaction was approved by the ACG Committee of our general partner and the Audit and Conflicts Committee of the general partner of TEPPCO. TEPPCO has no continued involvement in the contracts or in the operations of the Pioneer facility.

Jonah Joint Venture with TEPPCO. In August 2006, we became a joint venture partner with TEPPCO in Jonah, which owns the Jonah Gas Gathering System located in the Greater Green River Basin of southwestern Wyoming. The Jonah Gathering System gathers and transports natural gas produced from the Jonah and Pinedale fields to regional natural gas processing plants and major interstate pipelines that deliver natural gas to end-user markets.

Prior to entering into the Jonah joint venture, we managed the construction of the Phase V expansion and funded the initial construction costs under a letter of intent we entered into in February 2006. In connection with the joint venture arrangement, we and TEPPCO shared equally in the costs of the Phase V expansion, which is increased the capacity of the Jonah Gathering System from 1.5 Bcf/d to 2.4

Bcf/d and significantly reduced system operating pressures, which we anticipate will lead to increased production rates and ultimate reserve recoveries. The first portion of the expansion, which has increased the system gathering capacity to 2.0 Bcf/d, was completed in July 2007 and the final phase of this expansion was completed in June 2008. We managed the Phase V construction project. Currently, the gathering capacity of this system is 2.4 Bcf/d.

Since August 1, 2006, we and TEPPCO have equally shared in the construction costs of the Phase V expansion. TEPPCO has reimbursed us $306.5 million, which represents 50.0% of total Phase V costs incurred through December 31, 2008. We had a receivable of $1.0 million from TEPPCO at December 31, 2008 for Phase V expansion costs.

During the first quarter of 2008, Jonah initiated a separate project to increase gathering capacity on that portion of its system that serves the Pinedale production field. This new project is expected to increase overall capacity of the Jonah Gas Gathering System by an additional 0.2 Bcf/d. The total anticipated cost of this new project is $125.0 million, of which we will be responsible for our share of the construction costs.

TEPPCO was entitled to all distributions from the joint venture until specified milestones were achieved, at which point, we became entitled to receive 50.0% of the incremental cash flow from portions of the system placed in service as part of the expansion. Since the first phase of this expansion was reached in July 2007, we and TEPPCO have shared earnings based on a formula that takes into account our respective capital contributions, including expenditures by TEPPCO prior to the expansion.

At December 31, 2008, we owned an approximate 19.4% interest in Jonah and TEPPCO owns 80.6%. We operate the Jonah system. We account for our investment in the Jonah joint venture using the equity method.

The Jonah joint venture is governed by a management committee comprised of two representatives approved by us and two appointed by TEPPCO, each with equal voting power. After an in-depth consideration of all relevant factors, this transaction was approved by the ACG Committee of our general partner and the Audit and Conflicts Committee of the general partner of TEPPCO.

We have agreed to indemnify TEPPCO from any and all losses, claims, demands, suits, liabilities, costs and expenses arising out of or related to breaches of our representations, warranties, or covenants related to the Jonah joint venture. A claim for indemnification cannot be filed until the losses suffered by TEPPCO exceed $1.0 million. The maximum potential amount of future payments under the indemnity agreement is limited to $100.0 million. All indemnity payments are net of insurance recoveries that TEPPCO may receive from third-party insurance carriers. We carry insurance coverage that may offset any payments required under the indemnification.

Purchase of Houston-area pipelines from TEPPCO. In October 2006, we purchased certain idle pipeline assets in the Houston, Texas area from TEPPCO for $11.7 million in cash. The acquired pipelines became part of our Texas Intrastate System. The purchase of this asset was in accordance with the Board-approved management authorization policy.

Purchase and lease of pipelines for DEP South Texas NGL Pipeline System from TEPPCO. In January 2007, we purchased a 10-mile segment of pipeline from TEPPCO located in the Houston area for $8.0 million. This pipeline segment is part of the DEP South Texas NGL Pipeline System that commenced operations in January 2007. In addition, we entered into a lease with TEPPCO for an 11-mile interconnecting pipeline located in the Houston area that is part of the DEP South Texas NGL Pipeline System. Although the primary term of the lease expired in September 2007, it was renewed on a month-to-month basis until construction of a parallel pipeline was completed in early 2008. These transactions were in accordance with the Board-approved management authorization policy.

Texas Offshore Port System Joint Venture. In August 2008, we, together with TEPPCO and Oiltanking, announced the formation of the Texas Offshore Port System, a joint venture to design, construct, operate and own a Texas offshore crude oil port and a related onshore pipeline and storage system that would facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. The joint venture's primary project, referred to as "TOPS," includes (i) an offshore port (which will be located approximately 36 miles from Freeport, Texas), (ii) an onshore storage facility with approximately 3.9 million barrels of crude oil storage capacity, and (iii) an 85-mile crude oil pipeline system having a transportation capacity of up to 1.8 million barrels per day, that will extend from the offshore port to a storage facility near Texas City, Texas. The joint venture's complementary project, referred to as the Port Arthur Crude Oil Express (or "PACE") will transport crude oil from Texas City, including crude oil from TOPS, and will consist of a 75-mile pipeline and 1.2 million barrels of crude oil storage capacity in the Port Arthur, Texas area. The timing of the construction and related capital costs of the TOPS and PACE projects will be affected by the expansion plans of Motiva and the acquisition of requisite permits.

We, TEPPCO and Oiltanking each own, through our respective subsidiaries, a one-third interest in the joint venture. The aggregate cost of the TOPS and PACE projects is expected to be approximately $1.8 billion (excluding capitalized interest), with the majority of such capital expenditures currently expected to occur in 2010 and 2011. We and TEPPCO have each guaranteed up to approximately $700.0 million, which includes a contingency amount for potential cost overruns, of the capital contribution obligations of our respective subsidiary partners in the joint venture. As of December 31, 2008, our investment in the Texas Offshore Port System was $35.9 million.

Relationship with Energy Transfer Equity

Enterprise GP Holdings acquired equity method investments in Energy Transfer Equity and its general partner in May 2007. As a result, Energy Transfer Equity and its consolidated subsidiaries became related parties to our consolidated businesses.

For the year ended December 31, 2008 and the eight months ended December 31, 2007, we recorded $618.4 million and $294.4 million, respectively, of revenues from Energy Transfer Partners, L.P. ("ETP"), primarily from NGL marketing activities. We incurred $192.2 million and $35.2 million in costs of sales and operating costs and expenses for the year ended December 31, 2008 and the eight months ended December 31, 2007, respectively. We have a long-term revenue generating contract with Titan Energy Partners, L.P. ("Titan"), a consolidated subsidiary of ETP. Titan purchases substantially all of its propane requirements from us. The contract continues until March 31, 2010 and contains renewal and extension options. We and Energy Transfer Company ("ETC OLP") transport natural gas on each other's systems and share operating expenses on certain pipelines. ETC OLP also sells natural gas to us.

Relationship with Duncan Energy Partners

Duncan Energy Partners was formed in September 2006 and did not acquire any assets prior to February 5, 2007, which was the date it completed its initial public offering of 14,950,000 common units and acquired controlling interests in certain midstream energy businesses of EPO. The business purpose of Duncan Energy Partners is to acquire, own and operate a diversified portfolio of midstream energy assets and to support the growth objectives of EPO and other affiliates under common control. Duncan Energy Partners is engaged in the business of transporting and storing NGLs and petrochemical products and gathering, transporting, storing and marketing of natural gas.

At December 31, 2008, Duncan Energy Partners is owned 99.3% by its limited partners and 0.7% by its general partner, DEP GP, which is a wholly owned subsidiary of EPO. DEP GP is responsible for managing the business and operations of Duncan Energy Partners. DEP OLP, a wholly owned subsidiary of Duncan Energy Partners, conducts substantially all of Duncan Energy Partners' business.

At December 31, 2008, EPO owned approximately 74.1% of Duncan Energy Partners' limited partner interests and 100.0% of its general partner.

DEP I Midstream Businesses

On February 5, 2007, EPO contributed a 66.0% controlling equity interest in each of the DEP I Midstream Businesses (defined below) to Duncan Energy Partners in a dropdown of assets (the "DEP I dropdown"). EPO retained the remaining 34.0% equity interest in each of the DEP I Midstream Businesses. The DEP I Midstream Businesses consist of (i) Mont Belvieu Caverns, LLC ("Mont Belvieu Caverns"); (ii) Acadian Gas, LLC ("Acadian Gas"); (iii) Enterprise Lou-Tex Propylene Pipeline L.P. ("Lou-Tex Propylene"), including its general partner; (iv) Sabine Propylene Pipeline L.P. ("Sabine Propylene'), including its general partner; and (v) South Texas NGL Pipelines, LLC ("South Texas NGL").

As consideration for controlling equity interests in the DEP I Midstream Businesses and reimbursement for capital expenditures related to these businesses, Duncan Energy Partners distributed to EPO (i) $260.6 million of the $290.5 million of net proceeds from its initial public offering to EPO, (ii) $198.9 million in borrowings under its DEP I Revolving Credit Facility and (iii) a net 5,351,571 common units of Duncan Energy Partners. See Note 14 for information regarding the debt obligations of Duncan Energy Partners.

DEP II Midstream Businesses

On December 8, 2008, Duncan Energy Partners entered into the DEP II Purchase Agreement with EPO and Enterprise GTM, a wholly owned subsidiary of EPO. Pursuant to the DEP II Purchase Agreement, DEP OLP acquired 100.0% of the membership interests in Enterprise III from Enterprise GTM, thereby acquiring a 66.0% general partner interest in Enterprise GC, a 51.0% general partner interest in Enterprise Intrastate and a 51.0% membership interest in Enterprise Texas. Collectively, we refer to Enterprise GC, Enterprise Intrastate and Enterprise Texas as the "DEP II Midstream Businesses." EPO was the sponsor of this second dropdown transaction (the "DEP II dropdown"). Enterprise GTM retained the remaining limited partner and member interests in the DEP II Midstream Businesses.

As consideration for controlling equity interests in the DEP II Midstream Businesses, EPO received $280.5 million in cash and 37,333,887 Class B limited partner units having a market value of $449.5 million from Duncan Energy Partners. The Class B limited partner units automatically converted to common units of Duncan Energy Partners on February 1, 2009. The total value of the consideration provided to EPO and Enterprise GTM was $730.0 million. The cash portion of the consideration provided by Duncan Energy Partners in this dropdown transaction was derived from borrowings under the DEP II Term Loan Agreement. See Note 14 for information regarding the debt obligations of Duncan Energy Partners.

Generally, the DEP II dropdown transaction documents provide that to the extent that the DEP II Midstream Businesses generate cash sufficient to pay distributions to their partners or members, such cash will be distributed to Enterprise III (a wholly owned by Duncan Energy Partners) and Enterprise GTM (our wholly owned subsidiary) in an amount sufficient to generate an aggregate annualized return on their respective investments of 11.85%. Distributions in excess of this amount will be distributed 98.0% to Enterprise GTM and 2.0% to Enterprise III. The initial annual fixed return amount of 11.85% will be increased by 2.0% each calendar year beginning January 1, 2010. For example, the fixed return in 2010, assuming no other adjustments, would be 102.0% of 11.85%, or 12.087%.

Duncan Energy Partners paid a pro rated cash distribution of $0.1115 per unit on the Class B units with respect to the fourth quarter of 2008.

The borrowings of Duncan Energy Partners are presented as part of our consolidated debt; however, we do not have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

We may contribute other equity interests in our subsidiaries to Duncan Energy Partners and use the proceeds we receive from Duncan Energy Partners to fund our capital spending program.

Omnibus Agreement

On December 8, 2008, we entered into an amended and restated Omnibus Agreement with Duncan Energy Partners. The key provisions of this agreement are summarized as follows:

- indemnification for certain environmental liabilities, tax liabilities and right-of-way defects with respect to the DEP I and DEP II Midstream Businesses we contributed to Duncan Energy Partners in connection with the respective dropdown transactions;
- funding by EPO of 100.0% of post-February 5, 2007 capital expenditures incurred by South Texas NGL and Mont Belvieu Caverns with respect to certain expansion projects under construction at the time of Duncan Energy Partners' initial public offering;
- funding by EPO of 100.0% of post-December 8, 2008 capital expenditures (estimated at $1.4 million) to complete the Sherman Extension natural gas pipeline;
- a right of first refusal to EPO in our current and future subsidiaries and a right of first refusal on the material assets of such subsidiaries, other than sales of inventory and other assets in the ordinary course of business; and
- a preemptive right with respect to equity securities issued by certain of our subsidiaries, other than as consideration in an acquisition or in connection with a loan or debt financing.

We and Duncan Energy Partners have also agreed to negotiate in good faith any necessary amendments to the partnership or company agreements of the DEP II Midstream Businesses when either party believes that business circumstances have changed.

Our general partner's ACG Committee must approve amendments to the Omnibus Agreement when such amendments would adversely affect our unitholders.

EPO has indemnified Duncan Energy Partners against certain environmental liabilities, tax liabilities and right-of-way defects associated with the assets EPO contributed to Duncan Energy Partners in connection with the DEP I and DEP II dropdown transactions. These liabilities include both known and unknown environmental and related liabilities. These indemnifications terminate on February 5, 2010. There is an aggregate cap of $15.0 million on the amount of indemnity coverage, and Duncan Energy Partners is not entitled to indemnification until the aggregate amount of claims it incurs exceeds $250 thousand. Environmental liabilities resulting from a change of law after February 5, 2007 are excluded from the indemnity. In addition, EPO has indemnified Duncan Energy Partners for liabilities related to:

- certain defects in the easement rights or fee ownership interests in and to the lands on which any assets contributed to Duncan Energy Partners in connection with its initial public offering are located and failure to obtain certain consents and permits necessary to conduct its business that arise through February 5, 2010; and
- certain income tax liabilities attributable to the operation of the assets contributed to Duncan Energy Partners in connection with its initial public offering prior to February 5, 2007.

The Omnibus Agreement may not be amended without the prior approval of the ACG Committee if the proposed amendment will, in the reasonable discretion of DEP GP, adversely affect holders of its common units.

Neither we, nor EPO and any of its affiliates are restricted under the Omnibus Agreement from competing with Duncan Energy Partners. Except as otherwise expressly agreed in the ASA, EPO and any of its affiliates may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer Duncan Energy Partners the opportunity to purchase or construct those assets. These agreements are in addition to other agreements relating to business opportunities and potential conflicts of interest set forth in the ASA with EPO, EPCO and other affiliates of EPCO.

Under the Omnibus Agreement, EPO agreed to make additional contributions to Duncan Energy Partners as reimbursement for Duncan Energy Partners' 66.0% share of any excess construction costs above the (i) $28.6 million of estimated capital expenditures to complete Phase II expansions of the DEP South Texas NGL Pipeline System and (ii) $14.1 million of estimated construction costs for additional brine production capacity and above-ground storage reservoir projects at Mont Belvieu, Texas. Both projects were underway at the time of Duncan Energy Partners' initial public offering. EPO made cash contributions to Duncan Energy Partners of $32.5 million and $9.9 million in connection with the Omnibus Agreement during the years ended December 31, 2008 and 2007, respectively. The majority of these contributions related to funding the Phase II expansion costs of the DEP South Texas NGL Pipeline System. EPO will not receive an increased allocation of earnings or cash flows as a result of these contributions to South Texas NGL and Mont Belvieu Caverns.

Mont Belvieu Caverns' LLC Agreement

The Mont Belvieu Caverns' LLC Agreement (the "Caverns LLC Agreement") states that if Duncan Energy Partners elects to not participate in certain projects of Mont Belvieu Caverns, then EPO is responsible for funding 100.0% of such projects. To the extent such non-participated projects generate identifiable incremental cash flows for Mont Belvieu Caverns in the future, the earnings and cash flows of Mont Belvieu Caverns will be adjusted to allocate such incremental amounts to EPO by special allocation or otherwise. Under the terms of the Caverns LLC Agreement, Duncan Energy Partners may elect to acquire a 66.0% share of these projects from EPO within 90 days of such projects being placed in service.

EPO made cash contributions of $99.5 million and $38.1 million under the Caverns LLC Agreement during the years ended December 31, 2008 and 2007, respectively, to fund 100.0% of certain storage-related projects for the benefit of EPO's NGL marketing activities. At present, Mont Belvieu Caverns is not expected to generate any identifiable incremental cash flows in connection with these projects; thus, the sharing ratio for Mont Belvieu Caverns is not expected to change from the current sharing ratio of 66.0% for Duncan Energy Partners and 34.0% for EPO. EPO expects to make additional contributions of approximately $27.5 million to fund such projects in 2009. The constructed assets will be the property of Mont Belvieu Caverns.

In November 2008, the Caverns LLC Agreement was amended to provide that EPO would prospectively receive a special allocation of 100.0% of the depreciation related to projects that it has fully funded. For the two-month period in 2008 covered by the amendment, EPO was allocated depreciation expense of $1.0 million related to such projects.

The Caverns LLC Agreement also requires the allocation to EPO of operational measurement gains and losses. Operational measurement gains and losses are created when product is moved between storage wells and are attributable to pipeline and well connection measurement variances.

Company and Limited Partnership Agreements – DEP II Midstream Businesses

On December 8, 2007, the DEP II Midstream Businesses amended and restated their governing documents in connection with the DEP II dropdown transaction. Collectively, these amended and restated agreements provide for the following:

- the acquisition by Enterprise III (a wholly owned subsidiary of Duncan Energy Partners) from Enterprise GTM (our wholly owned subsidiary) of a 66.0% general partner interest in Enterprise GC, a 51.0% general partner interest in Enterprise Intrastate and a 51.0% member interest in Enterprise Texas;

- the payment of distributions in accordance with an overall "waterfall" approach that stipulates that to the extent that the DEP II Midstream Businesses collectively generate cash sufficient to pay distributions to their partners or members, such cash will be distributed first to Enterprise III (based on an initial defined investment of $730.0 million, the "Enterprise III Distribution Base") and then to Enterprise GTM (based on an initial defined investment of $452.1 million, the "Enterprise GTM Distribution Base") in amounts sufficient to generate an aggregate annualized fixed return on their respective investments of 11.85%. Distributions in excess of these amounts will be distributed 98.0% to Enterprise GTM and 2.0% to Enterprise III. The initial annual fixed return amount of 11.85% will be increased by 2.0% each calendar year beginning January 1, 2010. For example, the fixed return in 2010, assuming no other adjustments, would be 102.0% of 11.85%, or 12.087%;

- the funding of operating cash flow deficits in accordance with each owner's respective partner or member interest; and

- the election by either owner to fund cash calls associated with expansion capital projects. Since December 8, 2008, Enterprise III has elected to not participate in such cash calls and, as a result, Enterprise GTM has funded 100.0% of the expansion project costs of the DEP II Midstream Businesses. If Enterprise III later elects to participate in an expansion projects, then Enterprise III will be required to make a capital contribution for its share of the project costs.

  Any capital contributions to fund expansion projects made by either Enterprise III or Enterprise GTM will increase such partner's Distribution Base (and hence future priority return amounts) under the Company Agreement of Enterprise Texas. As noted, Enterprise III has declined participation in expansion project spending since December 8, 2008. As a result, Enterprise GTM has funded 100.0% of such growth capital spending and its Distribution Base has increased from $452.1 million at December 8, 2008 to $473.4 million at December 31, 2008. The Enterprise III Distribution Base was unchanged at $730.0 million at December 31, 2008.

Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates perform supporting or complementary roles to our other business operations. See Note 16 of the Notes to Consolidated Financial Statements for a discussion of this alignment of commercial interests. Since we and our affiliates hold ownership interests in these entities and directly or indirectly benefit from our related party transactions with such entities, they are presented here.

The following information summarizes significant related party transactions with our current unconsolidated affiliates:

- We sell natural gas to Evangeline, which, in turn, uses the natural gas to satisfy supply commitments it has with a major Louisiana utility. Revenues from Evangeline were $362.9 million, $268.0 million and $277.7 million for the years ended December 31, 2008, 2007 and 2006. In addition, Duncan Energy Partners furnished $1.0 million in letters of credit on behalf of Evangeline at December 31, 2008.

- We pay Promix for the transportation, storage and fractionation of NGLs. In addition, we sell natural gas to Promix for its plant fuel requirements. Revenues from Promix were $24.5 million, $17.3 million and $21.8 million for the years ended December 31, 2008, 2007 and 2006. Expenses with Promix were $38.7 million, $30.4 million and $34.9 million for the years ended December 31, 2008, 2007 and 2006.

- We pay Jonah for natural gas purchases from its gathering system. Expenses with Jonah were $38.3 million and $4.9 million for the years ended December 31, 2008 and 2007. We were not entitled to our 19.4% interest in Jonah until July 2007.

- We perform management services for certain of our unconsolidated affiliates. We charged such affiliates $9.9 million, $9.3 million and $8.9 million for the years ended December 31, 2008, 2007 and 2006.

Note 18. Provision for Income Taxes

Our provision for income taxes relates primarily to federal and state income taxes of Seminole and Dixie, our two largest corporations subject to such income taxes. In addition, with the amendment of the Texas Franchise Tax in 2006, we have become a taxable entity in the state of Texas. Our federal and state income tax provision is summarized below:

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Current:			
Federal	$ 4,922	$ 4,700	$ 7,694
State	19,350	3,871	1,148
Foreign	414	128	--
Total current	24,686	8,699	8,842
Deferred:			
Federal	760	2,784	6,109
State	928	3,774	6,372
Foreign	27	--	--
Total deferred	1,715	6,558	12,481
Total provision for income taxes	$ 26,401	$ 15,257	$ 21,323

A reconciliation of the provision for income taxes with amounts determined by applying the statutory U.S. federal income tax rate to income before income taxes is as follows:

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Pre Tax Net Book Income ("NBI")	$ 1,021,798	$ 579,574	$ 630,085
Revised Texas franchise tax	19,344	7,146	8,119
State income taxes (net of federal benefit)	505	325	(396)
Federal income taxes computed by applying the federal statutory rate to NBI of corporate entities	6,305	5,318	13,347
Taxes charged to cumulative effect of change in accounting principle	--	--	(3)
Valuation allowance	(1,412)	2,347	123
Other permanent differences	1,659	121	133
Provision for income taxes	$ 26,401	$ 15,257	$ 21,323
Effective income tax rate	2.6%	2.6%	3.4%

Significant components of deferred tax assets and deferred tax liabilities as of December 31, 2008 and 2007 are as follows:

	At December 31, 2008	At December 31, 2007
Deferred tax assets:		
Net operating loss carryovers	$ 26,311	$ 23,270
Property, plant and equipment	753	--
Credit carryover	26	26
Charitable contribution carryover	20	16
Employee benefit plans	2,631	3,214
Deferred revenue	964	642
Reserve for legal fees and damages	289	478
Equity investment in partnerships	596	409
AROs	76	80
Accruals	898	1,068
Total deferred tax assets	32,564	29,203
Valuation allowance	(3,932)	(5,345)
Net deferred tax assets	28,632	23,858
Deferred tax liabilities:		
Property, plant and equipment	92,899	40,520
Other	43	99
Total deferred tax liabilities	92,942	40,619
Total net deferred tax liabilities	$ (64,310)	$ (16,761)
Current portion of total net deferred tax assets	$ 1,397	$ 1,081
Long-term portion of total net deferred tax liabilities	$ (65,707)	$ (17,842)

We had net operating loss carryovers of $26.3 million and $23.3 million at December 31, 2008 and 2007, respectively. These losses expire in various years between 2009 and 2028 and are subject to limitations on their utilization. We record a valuation allowance to reduce our deferred tax assets to the amount of future tax benefit that is more likely than not to be realized. The valuation allowance was $3.9 million and $5.3 million at December 31, 2008 and 2007, respectively, and serves to reduce the recognized tax benefit associated with carryovers of our corporate entities to an amount that will, more likely than not, be realized. The $1.4 million decrease in valuation allowance for 2008 is comprised primarily of a $1.6 million decrease for Canadian Enterprise Gas Products, Ltd.

We have deferred tax liabilities on property plant and equipment of $92.9 million and $40.5 million at December 31, 2008 and 2007, respectively. The increase in 2008 is comprised primarily of $45.1 million related to the difference in book and tax basis of property, plant and equipment resulting from the acquisition of the remaining equity interest of Dixie Pipeline. See Note 12 for additional information.

On May 18, 2006, the State of Texas enacted House Bill 3 which revised the pre-existing state franchise tax. In general, legal entities that conduct business in Texas are subject to the Revised Texas Franchise Tax, including previously non-taxable entities such as limited liability companies, limited partnerships and limited liability partnerships. The tax is assessed on Texas sourced taxable margin which is defined as the lesser of (i) 70.0% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits.

Although the bill states that the Revised Texas Franchise Tax is not an income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers both revenues and expenses. Due to the enactment of the Revised Texas Franchise Tax, we recorded a net deferred tax liability of $0.9 million and $3.8 million during the years ended December 31, 2008 and 2007, respectively. The offsetting net charge of $0.9 million and $3.8 million is shown on our Statements of Consolidated Operations for the years ended December 31, 2008 and 2007, respectively, as a component of "Provision for income taxes."

Note 19. Earnings Per Unit

Basic earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the weighted-average number of distribution-bearing units outstanding during a period. Diluted earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the sum of (i) the weighted-average number of distribution-bearing units outstanding during a period (as used in determining basic earnings per unit); (ii) the weighted-average number of performance-based phantom units outstanding during a period; and (iii) the number of incremental common units resulting from the assumed exercise of dilutive unit options outstanding during a period (the "incremental option units").

In a period of net losses, restricted units, phantom units and incremental option units are excluded from the calculation of diluted earnings per unit due to their antidilutive effect. The dilutive incremental option units are calculated using the treasury stock method, which assumes that proceeds from the exercise of all in-the-money options at the end of each period are used to repurchase common units at an average market value during the period. The amount of common units remaining after the proceeds are exhausted represents the potentially dilutive effect of the securities.

The amount of net income or loss allocated to limited partner interests is net of our general partner's share of such earnings. The following table presents the allocation of net income to EPGP for the periods indicated:

	For The Year Ended December 31,		
	2008	**2007**	**2006**
Net income	$ 954,021	$ 533,674	$ 601,155
Less incentive earnings allocations to EPGP	(125,912)	(107,421)	(86,710)
Net income available after incentive earnings allocation	828,109	426,253	514,445
Multiplied by EPGP ownership interest	2.0%	2.0%	2.0%
Standard earnings allocation to EPGP	$ 16,562	$ 8,525	$ 10,289
Incentive earnings allocation to EPGP	$ 125,912	$ 107,421	$ 86,710
Standard earnings allocation to EPGP	16,562	8,525	10,289
Net income available to EPGP	$ 142,474	$ 115,946	$ 96,999

The following table presents our calculation of basic and diluted earnings per unit for the periods indicated:

	For The Year Ended December 31, 2008	2007	2006
Income before change in accounting principle and EPGP interest	$ 954,021	$ 533,674	$ 599,683
Cumulative effect of change in accounting principle	--	--	1,472
Net income	954,021	533,674	601,155
Net income available to EPGP	(142,474)	(115,946)	(96,999)
Net income available to limited partners	$ 811,547	$ 417,728	$ 504,156
BASIC EARNINGS PER UNIT			
Numerator			
Income before change in accounting principle and EPGP earnings allocation	$ 954,021	$ 533,674	$ 599,683
Cumulative effect of change in accounting principle	--	--	1,472
Net income available to EPGP	(142,474)	(115,946)	(96,999)
Net income available to limited partners	$ 811,547	$ 417,728	$ 504,156
Denominator			
Common units	435,397	432,513	413,472
Time-vested restricted units	1,980	1,446	970
Total	437,377	433,959	414,442
Basic earnings per unit			
Income per unit before change in accounting principle and EPGP earnings allocation	$ 2.18	$ 1.23	$ 1.45
Cumulative effect of change in accounting principle	--	--	--
Net income available to EPGP	(0.33)	(0.27)	(0.23)
Net income available to limited partners	$ 1.85	$ 0.96	$ 1.22
DILUTED EARNINGS PER UNIT			
Numerator			
Income before change in accounting principle and EPGP earnings allocation	$ 954,021	$ 533,674	$ 599,683
Cumulative effect of change in accounting principle	--	--	1,472
Net income available to EPGP	(142,474)	(115,946)	(96,999)
Net income available to limited partners	$ 811,547	$ 417,728	$ 504,156
Denominator			
Common units	435,397	432,513	413,472
Time-vested restricted units	1,980	1,446	970
Performance-based restricted units	5	9	20
Incremental option units	200	459	297
Total	437,582	434,427	414,759
Diluted earnings per unit			
Income per unit before change in accounting principle and EPGP earnings allocation	$ 2.18	$ 1.23	$ 1.45
Cumulative effect of change in accounting principle	--	--	--
Net income available to EPGP	(0.33)	(0.27)	(0.23)
Net income available to limited partners	$ 1.85	$ 0.96	$ 1.22

Note 20. Commitments and Contingencies

Litigation

On occasion, we or our unconsolidated affiliates are named as a defendant in litigation relating to our normal business activities, including regulatory and environmental matters. Although we are insured against various business risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings as a result of our ordinary business activities. We are unaware of any significant litigation, pending or threatened, that could have a significant adverse effect on our financial position, results of operations or cash flows.

On September 18, 2006, Peter Brinckerhoff, a purported unitholder of TEPPCO, filed a complaint in the Court of Chancery of New Castle County in the State of Delaware, in his individual capacity, as a putative class action on behalf of other unitholders of TEPPCO and derivatively on behalf of TEPPCO, concerning, among other things, certain transactions involving TEPPCO and us or our affiliates. Mr. Brinkerhoff filed an amended complaint on July 12, 2007. The amended complaint names as defendants (i) TEPPCO, its current and certain former directors, and certain of its affiliates; (ii) us and certain of our affiliates; (iii) EPCO.; and (iv) Dan L. Duncan.

The amended complaint alleges, among other things, that the defendants caused TEPPCO to enter into certain transactions that were unfair to TEPPCO or otherwise unfairly favored Enterprise Products Partners or its affiliates over TEPPCO. These transactions are alleged to include: (i) the joint venture to further expand the Jonah system entered into by TEPPCO and Enterprise Products Partners in August 2006; (ii) the sale by TEPPCO of its Pioneer natural gas processing plant to Enterprise Products Partners in March 2006; and (iii) certain amendments to TEPPCO's partnership agreement, including a reduction in the maximum tier of TEPPCO's IDRs in exchange for TEPPCO common units. The amended complaint seeks (i) rescission of the amendments to TEPPCO's partnership agreement; (ii) damages for profits and special benefits allegedly obtained by defendants as a result of the alleged wrongdoings in the amended complaint; and (iii) awarding plaintiff costs of the action, including fees and expenses of his attorneys and experts. We believe this lawsuit is without merit and intend to vigorously defend against it. See Note 17 for additional information regarding our relationship with TEPPCO.

On February 14, 2007, EPO received a letter from the Environment and Natural Resources Division ("ENRD") of the U.S. Department of Justice ("DOJ") related to an ammonia release in Kingman County, Kansas on October 27, 2004 from a pressurized anhydrous ammonia pipeline owned by a third party, Magellan Ammonia Pipeline, L.P. ("Magellan") and a previous release of ammonia on September 27, 2004 from the same pipeline. EPO was the operator of this pipeline until July 1, 2008. The ENRD has indicated that it may pursue civil damages against EPO and Magellan as a result of these incidents. Based on this correspondence from the ENRD, the statutory maximum amount of civil fines that could be assessed against EPO and Magellan is up to $17.4 million in the aggregate. EPO is cooperating with the DOJ and is hopeful that an expeditious resolution of this civil matter acceptable to all parties will be reached in the near future. Magellan has agreed to indemnify EPO for the civil matter. At this time, we do not believe that a final resolution of the civil claims by the ENRD will have a material impact on our consolidated financial position, results of operations or cash flows.

On October 25, 2006, a rupture in the Magellan Ammonia Pipeline resulted in the release of ammonia near Clay Center, Kansas. The pipeline has been repaired and environmental remediation tasks related to this incident have been completed. At this time, we do not believe that this incident will have a material impact on our consolidated financial position, results of operations or cash flows.

Several lawsuits have been filed by municipalities and other water suppliers against a number of manufacturers of reformulated gasoline containing methyl tertiary butyl ether ("MTBE"). In general, such suits have not named manufacturers of MTBE as defendants, and there have been no such lawsuits filed against our subsidiary that owns an octane-additive production facility. It is possible, however, that former MTBE manufacturers such as our subsidiary could ultimately be added as defendants in such lawsuits or in new lawsuits.

The Attorney General of Colorado on behalf of the Colorado Department of Public Health and Environment filed suit against us and others on April 15, 2008 in connection with the construction of a pipeline near Parachute, Colorado. The State sought a temporary restraining order and an injunction to halt construction activities since it alleged that the defendants failed to install measures to minimize damage to the environment and to follow requirements for the pipeline's stormwater permit and appropriate stormwater plan. The State's complaint also seeks penalties for the above alleged failures. Defendants and the State agreed to certain stipulations that, among other things, require us to install specified environmental protection measures in the disturbed pipeline right-of-way to comply with regulations. We have complied with the stipulations and the State has dismissed the portions of the complaint seeking the temporary restraining order and injunction. The State has not yet assessed penalties and we are unable to predict the amount of penalties that may be assessed. At this time, we do not believe that this incident will have a material impact on our consolidated financial position, results of operations or cash flows.

In January 2009, the State of New Mexico filed suit in District Court in Santa Fe County, New Mexico, under the New Mexico Air Quality Control Act. The lawsuit arose out of a February 27, 2008 Notice Of Violation issued to Marathon as operator of the Indian Basin natural gas processing facility located in Eddy County, New Mexico. We own a 40.0% undivided interest in the assets comprising the Indian Basin facility. The State alleges violations of its air laws, and Marathon believes there has been no adverse impact to public health or the environment, having implemented voluntary emission reduction measures over the years. The State seeks penalties above $100,000. Marathon continues to work with the State to determine if resolution of the case is possible.

Contractual Obligations

The following table summarizes our various contractual obligations at December 31, 2008. A description of each type of contractual obligation follows:

	Payment or Settlement due by Period						
Contractual Obligations	**Total**	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**
Scheduled maturities of long-term debt	$ 9,046,046	$ --	$ 554,000	$ 934,250	$ 1,517,596	$ 750,000	$ 5,290,200
Estimated cash payments for interest	$ 9,351,928	$ 544,658	$ 522,633	$ 471,253	$ 451,450	$ 369,673	$ 6,992,261
Operating lease obligations	$ 331,419	$ 32,299	$ 27,541	$ 27,831	$ 27,066	$ 24,481	$ 192,201
Purchase obligations:							
Product purchase commitments:							
Estimated payment obligations:							
Natural gas	$ 5,225,141	$ 323,309	$ 515,102	$ 635,000	$ 660,626	$ 487,984	$ 2,603,120
NGLs	$ 1,923,792	$ 969,870	$ 136,422	$ 136,250	$ 136,250	$ 136,250	$ 408,750
Petrochemicals	$ 1,746,138	$ 685,643	$ 376,636	$ 247,757	$ 181,650	$ 86,768	$ 167,684
Other	$ 37,455	$ 19,202	$ 3,459	$ 3,322	$ 3,051	$ 2,919	$ 5,502
Underlying major volume commitments:							
Natural gas (in BBtus)	981,955	56,650	93,150	115,925	120,780	93,950	501,500
NGLs (in MBbls)	56,622	23,576	4,726	4,720	4,720	4,720	14,160
Petrochemicals (in MBbls)	67,696	24,949	13,420	10,428	7,906	3,759	7,234
Service payment commitments	$ 529,402	$ 52,614	$ 50,902	$ 49,501	$ 47,025	$ 46,142	$ 283,218
Capital expenditure commitments	$ 521,262	$ 521,262	$ --	$ --	$ --	$ --	$ -

Scheduled Maturities of Long-Term Debt. We have long-term and short-term payment obligations under debt agreements such as the indentures governing EPO's senior notes and the credit agreement governing EPO's Multi-Year Revolving Credit Facility. Amounts shown in the preceding table represent our scheduled future maturities of debt principal for the periods indicated. See Note 14 for additional information regarding our consolidated debt obligations.

Operating Lease Obligations. We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Amounts shown in the preceding table represent minimum cash lease payment obligations under our operating leases with terms in excess of one year.

Our significant lease agreements involve (i) the lease of underground caverns for the storage of natural gas and NGLs, (ii) leased office space with an affiliate of EPCO, (iii) a railcar unloading terminal in Mont Belvieu, Texas and (iv) land held pursuant to right-of-way agreements. In general, our material lease agreements have original terms that range from 2 to 28 years and include renewal options that could extend the agreements for up to an additional 20 years.

Lease expense is charged to operating costs and expenses on a straight line basis over the period of expected economic benefit. Contingent rental payments are expensed as incurred. We are generally required to perform routine maintenance on the underlying leased assets. In addition, certain leases give us the option to make leasehold improvements. Maintenance and repairs of leased assets resulting from our operations are charged to expense as incurred. We did not make any significant leasehold improvements during the years ended December 31, 2008, 2007 or 2006; however, we did incur $9.3 million of repair costs associated with our lease of an underground natural gas storage facility in 2006.

The operating lease commitments shown in the preceding table exclude the non-cash, related party expense associated with retained leases contributed to us by EPCO at our formation. EPCO remains liable for the actual cash lease payments associated with these agreements, which it accounts for as operating leases. At December 31, 2008, the retained leases were for approximately 100 railcars. EPCO's minimum future rental payments under these leases are $0.7 million for each of the years 2009 through 2015 and $0.3 million for 2016. We record the full value of these payments made by EPCO on our behalf as a non-cash related party operating lease expense, with the offset to partners' equity accounted for as a general contribution to our partnership.

The retained lease agreements contain lessee purchase options, which are at prices that approximate fair value of the underlying leased assets. EPCO has assigned these purchase options to us. We have exercised our election under the retained leases to purchase a cogeneration unit in December 2008 for $2.3 million. Should we decide to exercise the purchase option associated with the remaining agreement, we would pay the original lessor $3.1 million in June 2016.

Lease and rental expense included in costs and expenses was $36.0 million, $38.5 million and $39.3 million during the years ended December 31, 2008, 2007 and 2006, respectively.

Purchase Obligations. We define a purchase obligation as an agreement to purchase goods or services that is enforceable and legally binding (unconditional) on us that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We have classified our unconditional purchase obligations into the following categories:

- We have long and short-term product purchase obligations for NGLs, certain petrochemicals and natural gas with third-party suppliers. The prices that we are obligated to pay under these contracts approximate market prices at the time we take delivery of the volumes. The preceding table shows our volume commitments and estimated payment obligations under these contracts for the periods indicated. Our estimated future payment obligations are based on the contractual price under each contract for purchases made at December 31, 2008 applied to all future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery. At December 31, 2008, we do not have any significant product purchase commitments with fixed or minimum pricing provisions with remaining terms in excess of one year.

- We have long and short-term commitments to pay third-party providers for services such as equipment maintenance agreements. Our contractual payment obligations vary by contract. The preceding table shows our future payment obligations under these service contracts.

- We have short-term payment obligations relating to our capital projects and those of our unconsolidated affiliates. These commitments represent unconditional payment obligations to vendors for services rendered or products purchased. The preceding table presents our share of such commitments for the periods indicated.

Commitments under equity compensation plans of EPCO

In accordance with our agreements with EPCO, we reimburse EPCO for our share of its compensation expense associated with certain employees who perform management, administrative and operating functions for us (see Note 17). This includes costs associated with unit option awards granted to these employees to purchase our common units. At December 31, 2008, there were 2,168,500 and 795,000 unit options outstanding under the EPCO 1998 Plan and EPD 2008 LTIP, respectively, for which we were responsible for reimbursing EPCO for the costs of such awards.

The weighted-average strike price of unit option awards outstanding at December 31, 2008 was $26.32 and $30.93 per common unit under the EPCO 1998 Plan and EPD 2008 LTIP, respectively. At December 31, 2008, 548,500 of these unit options were exercisable under the EPCO 1998 Plan. An additional 365,000, 480,000 and 775,000 of these unit options will be exercisable in 2009, 2010 and 2012, respectively under the EPCO 1998 Plan. The 795,000 unit options outstanding under the EPD 2008 LTIP will become exercisable in 2013. As these options are exercised, we will reimburse EPCO in the form of a special cash distribution for the difference between the strike price paid by the employee and the actual purchase price paid for the units awarded to the employee. See Note 5 for additional information regarding our accounting for equity awards.

Performance Guaranty

In December 2004, a subsidiary of ours entered into the Independence Hub Agreement (the "Agreement") with six oil and natural gas producers. The Agreement, as amended, obligated our subsidiary to construct the Independence Hub offshore platform and to process 1.0 Bcf/d of natural gas and condensate for the producers. We guaranteed to the producers the construction-related performance of our subsidiary up to an amount of $340.8 million. The performance guaranty expired during the second quarter of 2007.

Other Claims

As part of our normal business activities with joint venture partners and certain customers and suppliers, we occasionally have claims made against us as a result of disputes related to contractual agreements or similar arrangements. As of December 31, 2008, claims against us totaled approximately $15.4 million. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated. However, in our opinion, the likelihood of a material adverse outcome related to disputes against us is remote. Accordingly, accruals for loss contingencies related to these matters, if any, that might result from the resolution of such disputes have not been reflected in our consolidated financial statements.

Other Commitments

We transport and store natural gas, NGLs and petrochemicals for third parties under various processing, storage, transportation and similar agreements. These volumes are (i) accrued as product payables on our Consolidated Balance Sheets, (ii) in transit for delivery to our customers or (iii) held at our storage facilities for redelivery to our customers. We are insured against any physical loss of such volumes due to catastrophic events. Under the terms of our natural gas, NGL and petrochemical storage agreements, we are generally required to redeliver volumes to the owner on demand. At December 31, 2008, NGL and petrochemical products aggregating 29.6 million barrels were due to be redelivered to their owners along with 18.5 BBtus of natural gas. See Note 2 for more information regarding accrued product payables.

Note 21. Significant Risks and Uncertainties

Nature of Operations in Midstream Energy Industry

Our operations are within the midstream energy industry, which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs, certain petrochemicals and crude oil. As such, our financial condition, results of operations and cash flows may be affected by changes in the commodity prices of these hydrocarbon products, including changes in the relative price levels among these products. In general, the prices of natural gas, NGLs, crude oil and other hydrocarbon products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control.

Our profitability could be impacted by a decline in the volume of hydrocarbon products transported, gathered or processed at our facilities. A material decrease in natural gas or crude oil production or crude oil refining for reasons such as depressed commodity prices or a decrease in exploration and development activities, could result in a decline in the volume of natural gas, NGLs and crude oil handled by our facilities.

A reduction in demand for NGL products by the petrochemical, refining or heating industries, whether because of (i) general economic conditions, (ii) reduced demand by consumers for the end products made using NGLs, (iii) increased competition from petroleum-based products due to pricing differences, (iv) adverse weather conditions, (v) government regulations affecting energy commodity prices, production levels of hydrocarbons or the content of motor gasoline or (vi) other reasons, could adversely affect our financial position, results of operations and cash flows.

Credit Risk due to Industry Concentrations

A substantial portion of our revenues are derived from companies in the domestic natural gas, NGL and petrochemical industries. This concentration could affect our overall exposure to credit risk since these customers may be affected by similar economic or other conditions. We generally do not require collateral for our accounts receivable; however, we do attempt to negotiate offset, prepayment, or automatic debit agreements with customers that are deemed to be credit risks in order to minimize our potential exposure to any defaults.

Our revenues are derived from a wide customer base. During 2008 our largest customer was LBI and its affiliates, which accounted for 9.6% of our consolidated revenues. In 2007 and 2006, our largest customer was The Dow Chemical Company and its affiliates, which accounted for 6.9% and 6.1%, respectively, of our consolidated revenues.

On January 6, 2009, LBI announced that its U.S. operations had voluntarily filed to reorganize under Chapter 11 of the U.S. Bankruptcy Code. At the time of the bankruptcy filing, we had approximately $17.3 million of credit exposure to LBI, which was reduced to approximately $10.0 million through remedies provided under certain pipeline tariffs. In addition, we are seeking to have LBI accept certain contracts and have filed claims pursuant to current Bankruptcy Court Orders that we expect will allow us to recover the majority of the remaining credit exposure.

For 2008, LBI accounted for 10.2%, or $1.6 billion, of revenues attributable to our NGL Pipelines & Services business segment and 19.2%, or $516.2 million, of revenues attributable to our Petrochemical Services business segment.

Counterparty Risk with Respect to Financial Instruments

In those situations where we are exposed to credit risk in our financial instrument transactions, we analyze the counterparty's financial condition prior to entering into an agreement, establish credit and/or margin limits and monitor the appropriateness of these limits on an ongoing basis. Generally, we do not require collateral nor do we anticipate nonperformance by our counterparties.

Weather-Related Risks

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other coverages, the scope and amounts of which are customary and sufficient for the nature and extent of our operations. While we believe EPCO maintains adequate insurance coverage on our behalf, insurance will not cover every type of damage or interruption that might occur. If we were to incur a significant liability for which we were not fully insured, it could have a material impact on our consolidated financial position, results of operations and cash flows. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient to reimburse us for our repair costs or lost income. Any event that interrupts the revenues generated by our consolidated operations, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to pay distributions to our partners and, accordingly, adversely affect the market price of our common units.

For windstorm events such as hurricanes and tropical storms, EPCO's deductible for onshore physical damage is $10.0 million per storm. For offshore assets, the windstorm deductible is $10.0 million per storm plus a one-time $15.0 million aggregate deductible per policy period. For non-windstorm events, EPCO's deductible for onshore and offshore physical damage is $5.0 million per occurrence. In meeting the deductible amounts, property damage costs are aggregated for EPCO and its affiliates, including us. Accordingly, our exposure with respect to the deductibles may be equal to or less than the stated amounts depending on whether other EPCO or affiliate assets are also affected by an event.

To qualify for business interruption coverage in connection with a windstorm event, covered assets must be out-of-service in excess of 60 days for onshore assets and 75 days for offshore assets. To qualify for business interruption coverage in connection with a non-windstorm event, covered onshore and offshore assets must be out-of-service in excess of 60 days.

The following is a discussion of the general status of our insurance claims related to recent significant storm events. To the extent we include any estimate or range of estimates regarding the dollar value of damages, please be aware that a change in our estimates may occur as additional information becomes available.

Hurricane Ivan insurance claims. During the year ended December 31, 2008, we did not receive any reimbursements from insurance carriers related to property damage claims associated with this storm. During the year ended December 31, 2007, we received cash reimbursements from insurance carriers totaling $1.3 million, related to property damage claims. If the final recovery of funds is different than the amount previously expended, we will recognize an income impact at that time.

We have submitted business interruption insurance claims for our estimated losses caused by Hurricane Ivan, which struck the eastern U.S. Gulf Coast region in September 2004. During the year ended December 31, 2008, we did not receive any proceeds from these claims. During the year ended December 31, 2007, we received $0.4 million of nonrefundable cash proceeds from such claims. We are continuing our efforts to collect residual balances from this storm. To the extent we receive nonrefundable cash proceeds from business interruption insurance claims, they are recorded as a gain in our Statements of Consolidated Operations in the period of receipt.

Hurricanes Katrina and Rita insurance claims. Hurricanes Katrina and Rita, both significant storms, affected certain of our Gulf Coast assets in August and September of 2005, respectively. With respect to these storms, we have $30.5 million of estimated property damage claims outstanding at December 31, 2008, that we believe are probable of collection during the period 2009. We continue to pursue collection of our property damage claims related to these named storms. As of December 31, 2008, we had received all proceeds from our business interruption claims related to these storm events.

Hurricanes Gustav and Ike insurance claims. In the third quarter of 2008, our onshore and offshore facilities located along the Gulf Coast of Texas and Louisiana were adversely impacted by Hurricanes Gustav and Ike. The disruptions in natural gas, NGL and crude oil production caused by these storms resulted in decreased volumes for some of our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which, in turn, caused a decrease in gross operating margin from these operations. As a result of our allocated share of EPCO's insurance deductibles for windstorm coverage, we expensed a combined $47.9 million of repair costs for property damage in connection with these two storms. We expect to file property damage insurance claims to the extent repair costs exceed deductible amounts. Due to the recent nature of these storms, we are still evaluating the total cost of repairs and the potential for business interruption claims on certain assets.

Proceeds from Business Interruption and Property Damage Claims

The following table summarizes proceeds we received during the periods indicated from business interruption and property damage insurance claims with respect to certain named storms:

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Business interruption proceeds:			
Hurricane Ivan	$ --	$ 377	$ 17,382
Hurricane Katrina	501	19,005	24,500
Hurricane Rita	662	14,955	22,000
Other	--	996	--
Total proceeds	1,163	35,333	63,882
Property damage proceeds:			
Hurricane Ivan	--	1,273	24,104
Hurricane Katrina	9,404	79,651	7,500
Hurricane Rita	2,678	24,105	3,000
Other	--	184	--
Total proceeds	12,082	105,213	34,604
Total	$ 13,245	$ 140,546	$ 98,486

At December 31, 2008, we have $39.0 million of estimated property damage claims outstanding related to these storms that we believe are probable of collection through 2009. In February 2009, we collected $20.8 million of the amounts outstanding. To the extent we estimate the dollar value of such damages, please be aware that a change in our estimates may occur as additional information becomes available.

During 2008, we collected $0.2 million of business interruption proceeds that were not related to storm events.

Note 22. Supplemental Cash Flow Information

We determine net cash flows provided by operating activities using the indirect method, which adjusts net income for items that did not affect cash. Under GAAP, we use the accrual basis of accounting to determine net income. This basis of accounting requires that we record revenue when earned and expenses when incurred. Earned revenues may include credit sales that have not been collected in cash and expenses incurred that may not have been paid in cash. The extent to which changes in operating accounts influence net cash flows provided by operating activities generally depends on the following:

- The timing of cash receipts from revenue transactions and cash payments for expense transactions near the end of each reporting period. For example, if significant cash receipts are posted on the last day of the current reporting period, but subsequent payments on expense invoices are made on the first day of the next reporting period, net cash flows provided by operating activities will reflect an increase in the current reporting period that will be reduced as payments are made in the next period. We employ prudent cash management practices and monitor our daily cash requirements to meet our ongoing liquidity needs.

- If commodity or other prices increase between reporting periods, changes in accounts receivable and accounts payable and accrued expenses may appear larger than in previous periods; however, overall levels of receivables and payables may still reflect normal ranges. From a receivables standpoint, we monitor the amount of credit extended to customers.

- Additions to inventory for forward sales transactions or other reasons or increased expenditures for prepaid items would be reflected as a use of cash and reduce overall cash provided by operating activities in a given reporting period. As these assets are charged to expense in subsequent periods, the expense amount is reflected as a positive change in operating accounts; however, there is no impact on operating cash flows.

In addition to the adjustments noted above, non-cash charges in the income statement are added back to net income and non-cash credits are deducted to compute net cash flows provided by operating activities. Examples of non-cash charges include depreciation and amortization.

The following table provides information regarding (i) the net effect of changes in our operating assets and liabilities; (ii) cash payments for interest and (iii) cash payments for federal and state income taxes for the periods indicated.

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Decrease (increase) in:			
Accounts and notes receivable – trade	$ 744,277	$ (640,092)	$ 164,240
Accounts receivable – related party	16,494	(63,254)	(8,612)
Inventories	(15,425)	(14,051)	(66,288)
Prepaid and other current assets	(26,156)	41,266	14,261
Other assets	(2,910)	5,630	(22,581)
Increase (decrease) in:			
Accounts payable – trade	(18,372)	36,870	(1,509)
Accounts payable – related party	15,126	17,111	(10,769)
Accrued product payables	(1,080,034)	862,941	(8,344)
Accrued expenses	1,920	120,054	(62,963)
Accrued interest	20,902	40,107	19,671
Other current liabilities	(17,913)	37,248	74,206
Other liabilities	4,661	(2,524)	(7,894)
Net effect of changes in operating accounts	$ (357,430)	$ 441,306	$ 83,418
Cash payments for interest, net of $71,584, $75,476 and $55,660 capitalized in 2008, 2007 and 2006, respectively	$ 441,550	$ 325,339	$ 213,365
Cash payments for federal and state income taxes	$ 4,830	$ 5,760	$ 10,497

The following table provides supplemental cash flow information regarding business combinations we completed during the periods indicated. See Note 12, for additional information regarding our business combination transactions.

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Assets acquired	$ 254,322	$ 37,037	$ 477,015
Less liabilities assumed	(52,162)	(1,244)	(19,403)
Net assets acquired	202,160	35,793	457,612
Less equity issued	--	--	(181,112)
Cash used for business combinations, net of cash received	$ 202,160	$ 35,793	$ 276,500

We incurred liabilities for construction in progress that had not been paid at December 31, 2008, 2007 and 2006 of $90.6 million, $95.5 million and $195.1 million, respectively. Such amounts are not included under the caption “Capital expenditures” on the Statements of Consolidated Cash Flows.

Third parties may be obligated to reimburse us for all or a portion of expenditures on certain of our capital projects. The majority of such arrangements are associated with projects related to pipeline construction and production well tie-ins. We received $25.8 million, $57.5 million and $60.5 million as contributions in aid of our construction costs during the years ended December 31, 2008, 2007 and 2006, respectively.

Note 23. Quarterly Financial Information (Unaudited)

The following table presents selected quarterly financial data for the years ended December 31, 2008 and 2007:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
For the Year Ended December 31, 2008:				
Revenues	$ 5,684,535	$ 6,339,615	$ 6,297,902	$ 3,583,604
Operating income	366,732	374,270	319,116	353,128
Income before change in accounting principle	259,609	263,270	203,081	228,061
Net income	259,609	263,270	203,081	228,061
Income per unit before change in accounting principle:				
Basic	$ 0.51	$ 0.52	$ 0.38	$ 0.44
Diluted	$ 0.51	$ 0.52	$ 0.38	$ 0.44
Net income per unit:				
Basic	$ 0.51	$ 0.52	$ 0.38	$ 0.44
Diluted	$ 0.51	$ 0.52	$ 0.38	$ 0.44
For the Year Ended December 31, 2007:				
Revenues	$ 3,322,854	$ 4,212,806	$ 4,111,996	$ 5,302,469
Operating income	187,924	214,562	210,830	269,721
Income before change in accounting principle	112,045	142,154	117,606	161,869
Net income	112,045	142,154	117,606	161,869
Income per unit before change in accounting principle:				
Basic	$ 0.20	$ 0.26	$ 0.20	$ 0.30
Diluted	$ 0.20	$ 0.26	$ 0.20	$ 0.30
Net income per unit:				
Basic	$ 0.20	$ 0.26	$ 0.20	$ 0.30
Diluted	$ 0.20	$ 0.26	$ 0.20	$ 0.30

Note 24. Condensed Financial Information of EPO

EPO conducts substantially all of our business. Currently, we have no independent operations and no material assets outside those of EPO. EPO consolidates the financial statements of Duncan Energy Partners with those of its own.

Enterprise Products Partners L.P. guarantees the debt obligations of EPO, with the exception of the Dixie revolving credit facility (terminated January 2009) and the Duncan Energy Partners' debt obligations. If EPO were to default on any of its guaranteed debt, Enterprise Products Partners L.P. would be responsible for full repayment of that obligation. See Note 14 for additional information regarding our consolidated debt obligations.

The reconciling items between our consolidated financial statements and those of EPO are insignificant. The following table presents condensed consolidated balance sheet data for EPO at the dates indicated:

	At December 31, 2008	At December 31, 2007
ASSETS		
Current assets	$ 2,175,555	$ 2,545,297
Property, plant and equipment, net	13,154,774	11,587,264
Investments in and advances to unconsolidated affiliates, net	949,526	858,339
Intangible assets, net	855,416	917,000
Goodwill	706,884	591,652
Other assets	126,619	115,458
Total	$ 17,968,774	$ 16,615,010
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities	$ 2,222,650	$ 3,044,002
Long-term debt	9,108,410	6,906,145
Other long-term liabilities	147,339	95,112
Minority interest	404,214	439,854
Partners' equity	6,086,161	6,129,897
Total	$ 17,968,774	$ 16,615,010
Total EPO debt obligations guaranteed Enterprise Products Partners L.P.	$ 8,561,796	$ 6,686,500

The following table presents condensed consolidated statements of operations data for EPO for the periods indicated:

	For the Year Ended December 31, 2008	2007	2006
Revenues	$ 21,905,656	$ 16,950,125	$ 13,990,969
Costs and expenses	20,549,026	16,094,248	13,148,530
Equity in earnings of unconsolidated affiliates	59,104	29,658	21,565
Operating income	1,415,734	885,535	864,004
Other expense	(391,457)	(305,236)	(231,876)
Income before provision for income taxes, minority interest and change in accounting principle	1,024,277	580,299	632,128
Provision for income taxes	(26,376)	(15,317)	(21,198)
Income before minority interest and change in accounting principle	997,901	564,982	610,930
Minority interest	(41,638)	(30,737)	(9,190)
Income before change in accounting principle	956,263	534,245	601,740
Cumulative effect of change in accounting principle	--	--	1,472
Net income	$ 956,263	$ 534,245	$ 603,212

Note 25. Subsequent Events

In January 2009, we sold 10,590,000 common units (including an over-allotment of 990,000 common units) to the public at an offering price of $22.20 per unit. We used the net offering proceeds of $225.6 million to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility, which may be reborrowed to fund capital expenditures and other growth projects, and for general partnership purposes.